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IMPLEMENTATION OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

HEARINGS

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

NINETY-NINTH CONGRESS

SECOND SESSION

ON THE

IMPLEMENTATION OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

JUNE 3 AND 5, 1986

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IMPLEMENTATION OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

TUESDAY, JUNE 3, 1986

U.S. Senate,
Committee on Energy and Natural Resources,
Washington, DC.

The committee met, pursuant to notice, at 9:45 a.m., in room SD-366, Dirksen Senate Office Building, Hon. James A. McClure (chairman) presiding.

Present: Senators McClure, Warner, Nickles, Hecht, and Evans.

Also present: E. David Doane, senior counsel; Richard D. Grundy, senior professional staff member; and William B. Conway, counsel for the minority.

OPENING STATEMENT OF HON. JAMES A. McCLURE, A U.S. SENATOR FROM THE STATE OF IDAHO, AS PRESENTED BY SENATOR NICKLES

Senator Nickles. Good morning. Today we are holding an oversight hearing on the implementation provisions of the Public Utility Regulatory Policies Act of 1978, which is commonly known as PURPA. Specifically, the two provisions are sections 201 and 210, which relate to cogeneration and small power production.

PURPA is one of five separate statutes that comprise the National Energy Act, which was enacted in 1978 in response to what was widely viewed as a national energy crisis that had persisted in various degrees since 1973.

A fundamental purpose of PURPA was to encourage the development of cogeneration and small power production, thereby reducing our Nation's dependence on imported crude oil, increasing our reliance on alternative energy sources, and improving the efficiency of our energy consumption and electric power production.

I would ask that the balance of Senator McClure's statement and a statement by Senator Johnston be entered in the record.

[The prepared statements of Senator McClure and Senator Johnston follow:]

OPENING STATEMENT OF CHAIRMAN McCLURE

This is an oversight hearing on the implementation of two provisions of the Public Utility Regulatory Policies Act of 1978, which is commonly known as PURPA. Specifically, the two provisions are sections 201 and 210, which relate to cogeneration and small power production.

PURPA is one of five separate statutes that comprise the National Energy Act, which was enacted in 1978 in response to what was widely viewed as a national energy crisis that had persisted in varying degrees since 1973. A fundamental purpose of PURPA was to encourage the development of cogeneration and small power production, thereby reducing our nation's dependence on imported crude oil, increasing our reliance on alternative energy sources, and improving the efficiency of our energy consumption and electric power production.

For the first five years following enactment of PURPA, the development of cogeneration and small power production was quite limited. It took time for the Federal Energy Regulatory Commission to adopt implementing regulations, and it took additional time for the States to respond to the Commission's rules. Also, developers were understandably cautious in making investments until the legal challenges to PURPA were finally resolved, and that did not occur until 1983.

In the past two years, we have seen dramatic growth in non-utility electric generation, particularly gas-fired cogeneration.

THUS, WE NOW HAVE A TRACK RECORD TO REVIEW. WE ARE IN A GOOD POSITION TO TAKE A HARD LOOK AT HOW PURPA HAS BEEN IMPLEMENTED, AND TO DECIDE WHETHER ANY MODIFICATIONS SHOULD BE MADE IN THE STATUTORY LANGUAGE.

THIS HEARING WILL FOCUS ON THREE BASIC QUESTIONS. FIRST, TO WHAT EXTENT HAVE THE BASIC GOALS OF PURPA BEEN ACHIEVED? SECOND, WHAT NEW PROBLEMS HAVE BEEN CREATED, PARTICULARLY THOSE INVOLVING THE ISSUE OF FAIRNESS TO ELECTRIC UTILITY RATEPAYERS. THIRD, TO WHAT EXTENT ARE THOSE PROBLEMS SELF-CORRECTING; THAT IS, HAVE THE STATES DISPLAYED AN ABILITY TO RESPOND TO CHANGING CIRCUMSTANCES AND MODIFY THEIR REQUIREMENTS ACCORDINGLY, THUS PERHAPS OBVIATING THE NEED FOR CORRECTIVE LEGISLATION AT THE FEDERAL LEVEL.

SINCE THE TIME OF ITS ENACTMENT, PURPA HAS BEEN HIGHLY CONTROVERSIAL. THIS HEARING IS PARTLY INTENDED TO SERVE AS A FORUM FOR COMPLAINTS FROM ALL SIDES, AND FOR RESPONSES TO THOSE COMPLAINTS. THE COMPLAINTS ENCOMPASS A LONG LIST OF ISSUES. CERTAINLY, A MAJOR ISSUE IS THE COMPUTATION OF FULL AVOIDED COST RATES. MANY UTILITIES CONTEND THAT NO UTILITY SHOULD BE REQUIRED TO PAY FOR POWER FROM QUALIFYING FACILITIES AT RATES EXCEEDING ITS ACTUAL AVOIDED COST.

ANOTHER IMPORTANT ISSUE INVOLVES THE MANDATORY PURCHASE RULE. IS IT REASONABLE TO CONTINUE TO COMPEL UTILITIES TO PURCHASE POWER FROM QUALIFYING FACILITIES WHEN THEY DO NOT NEED IT, WHEN THEIR RESERVE MARGINS ARE MORE THAN ADEQUATE? A RELATED QUESTION IS WHETHER A UTILITY SHOULD BE COMPELLED TO INCLUDE CAPACITY PAYMENTS IN THE RATES IT PAYS FOR POWER FROM QUALIFYING FACILITIES, IF IT ALREADY HAS EXCESS CAPACITY ON ITS SYSTEM.

Finally, I would note that in relying primarily on the States to carry out the requirements of PURPA, we pay the price of having to accept a wide degree of diversity in the performance of the States. Some States, such as California, have aggressively promoted cogeneration and small power production, but many others have not. Sellers of power from qualifying facilities would like to see a better performance by the latter group of States, those that have not embraced PURPA with enthusiasm. Thus, we are faced with the question of whether PURPA should be amended to include a new set of minimum standards that would create greater opportunities for the development of qualifying facilities in some areas of the country.

As the starting point for addressing these issues, the Committee today will receive testimony from two panels of witnesses. The first consists of electric utilities that buy power from qualifying facilities. The second panel is comprised of representatives of cogenerators, and small power producers. The hearing will continue on Thursday with testimony from three additional panels. The first panel will consist of representatives of FERC and State commissions. The remaining witnesses will address environmental and energy policy issues.

PURPA Oversight Hearing Opening Statement
by Senator J. Bennett Johnston

Today we examine the impact of qualifying facilities development under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978, known by its acronym as PURPA. It has often been observed, Mr. Chairman, that revolutionary policy changes are not always appreciated at the time they are made. Certainly that is true of the law that has made widespread cogeneration and small power production possible.

In 1977 and 1978 when PURPA was being developed Congress had its mind on a whole host of energy initiatives, among them the Natural Gas Policy Act, the Department of Energy Organization Act, and the Fuel Use Act. Within PURPA itself many different electric policy issues were addressed including: utility ratemaking standards, wheeling, crude oil transportation, and retail natural gas sales. Thus, Sections 201 and 210 of PURPA were only two short sections in a sea of energy statutes. I won't say they went unnoticed, but in retrospect the attention we paid in 1978 to these new creations called "qualifying facilities" hardly anticipated their impact.

Undeniably, the development of cogeneration and small power production under PURPA has had, and will continue to have, a significant impact on the construction of electric generation in this country. As of January 1 of this year the Federal Energy Regulatory Commission had received 2,305 applications for qualifying facilities with capacities totalling approximately 34,000 megawatts or roughly 5 percent of our total generation capacity. There seems to be general agreement that many of the facilities represented by these filings will never be built, but even if only half of them materialize, the amount of power will be large. Moreover, there is every indication that qualifying facilities development will continue at an accelerated pace. One study has estimated that cogeneration alone will make up 5 percent of our total generation capacity by the year 2000.

Against this backdrop of extraordinary growth, I believe that two issues loom rather largely. First, are consumers really benefitting from qualifying facilities development? One of the principal purposes of PURPA was to ensure equitable rates for consumers. Yet increasingly we have heard that utilities are being required to pay rates to qualifying facilities that are in excess of avoided costs. If that is true, consumers are by definition subsidizing qualifying facilities, a state of affairs that I don't believe anyone would defend.

Second, is qualifying facilities development contributing to the Nation's energy independence in accordance with the goal of PURPA? It is somewhat troubling that much of existing and projected qualifying facilities development is in petroleum and gas-fired cogeneration, and there have been arguments that we are in fact burning more oil and gas as a result of PURPA, rather than less. Coming from Louisiana, and with the oil and gas industry in my state being as depressed as it is, I am a little hesitant to get into this issue. However, long gas lines and curtailment may always return, and I think it would be foolish indeed if we are actively subsidizing the consumption of our most precious fuels in ways that are ultimately inefficient.

Beyond these two issues there are many others raised by qualifying facilities development under PURPA. I want to emphasize that I have not prejudged any of them. However, because qualifying facilities have so dramatically affected the generation of electricity in this country, and will continue to do so, I believe we must examine them with a critical eye. I look forward to hearing the testimony of our witnesses and having the opportunity to ask them questions.

Senator **Nickles**. I am pleased that we have a couple of our colleagues, Senator Hecht and Senator Evans with us today. Did you have any opening comment?

Senator **Hecht**. Thank you; no, sir.

Senator **Nickles**. Senator Evans, do you have any comment?

STATEMENT OF HON. DANIEL J. EVANS, A U.S. SENATOR FROM THE STATE OF WASHINGTON

Senator **Evans**. Mr. Chairman, I have a fairly comprehensive opening statement. I won't read it all. I would ask that it all be entered into the record. But let me just state the first two paragraphs, which, I think, summarize the rest of the statement.

As you well know, reassessing the PURPA legislation that Congress passed in 1978 has been a concern of mine for quite a while. Simply, I believe the conditions of electricity supply and demand have changed sufficiently since the late 1970's to warrant a comprehensive set of hearings on the benefits afforded certain producers of electricity under PURPA.

Too often, we spend too little of our time here in Congress on oversight of existing laws and too much time on creating new legislation. For that reason, I asked earlier this year that the committee hold hearings on this subject.

As our hearings in the committee last July demonstrated, electric utilities today face a complex, rapidly changing world. I believe there was a consensus at the hearing that we do not face immediately blackouts or brownouts in any region of this country. There are substantial surpluses of electric power in many parts of the country, including the Pacific Northwest.

With the completion of the generating projects under construction today, both central station and PURPA-related, most utilities will not need to build new firm capacity until the mid-1990's. In addition, the regulatory environment is sufficiently uncertain that a CEO of a private utility cannot justify the enormous investments involved in new central station capacity.

Mr. Chairman, I would ask that the rest of the statement be entered into the record. I hope these hearings will perhaps lead us to renewal, changes, modifications of the PURPA legislation that will better meet the needs of today and the rest of the century than the existing legislation, I believe, does.

[The prepared statement of Senator Evans follows:]

STATEMENT BY SENATOR DANIEL J. EVANS

Senate Energy and Natural Resources Committee
Oversight Hearings on PURPA

June 3, 1986

Mr. Chairman, first let me thank you for scheduling these hearings today. As you well know, reassessing the PURPA legislation that Congress passed in 1978 has been a concern of mine for quite a while. Simply, I believe the conditions of electricity supply and demand have changed sufficiently since the late 1970's to warrant a comprehensive set of hearings on the benefits afforded certain producers of electricity under PURPA. Too often, we spend too little of our time here in Congress on oversight on existing laws and too much time on creating new legislation. For that reason, I asked earlier this year that the Committte hold hearings on this subject.

As our hearings in the Committee last July demonstrated, electric utilities today face a complex, rapidly changing world.

I believe there was a consensus at the hearing that we don't face immediate blackouts or brownouts in any region of this country. There are substantial surpluses of electric power in many parts of the country, including the Pacific Northwest. With the completion of the generating projects under construction today, both central station and PURPA-related, most utilities won't need to build new firm capacity until the mid-1990's. In addition, the regulatory environment is sufficiently uncertain that a CEO of a private utility cannot justify the enormous investments involved in new central station capacity. As Keith Turley, the CEO of Arizona Public Service, stated at the hearing:

> ". . . I took the position that I was no longer willing to recommend to my Board of Director the launching of any new power projects unless the poltiical, business, labor, and consumer interests were in agreement with the need for a new energy supply for a growing Arizona. It is my experience that the construction periods for major facilities, which now extend from 10 to 15 years, are longer than the memories of respective authorities that regulate our industry, leaving hindsight as the measure of the quality of utility managements' decision."

I believe that utilities have, by necessity, become a good deal more creative in extracting greater efficiencies out of existing resources and in managing their overall systems better. They face a wide variety of possible options, including offering residential and commercial customers incentives and grants for conservation, or more accurately, the buyback of capacity from its customers. I believe utilities should be more aggressively pursuing this option. Utilities are also planning to build more transmission capacity to import power from surplus regions to deficit regions at prices that are cheaper than building new resources. Some of this power is coming from Canada, especially in the Northeast, but most of it is within the United States. I believe there are enormous opportunities in this area. We have already shown the size of such benefits in building the huge tie-lines between the Pacific Northwest and California, which are even greater due to the complementarity of our peaking seasons.

Utilities also face a burgeoning supply of power from producers of congeration and small hydro whose capacity they are obligated to purchase under PURPA. Cogeneration has boomed into an enormous growth industry over the past several years. It is an unregulated industry in the traditional sense of utility regulation and has been built up by a different breed of energy entrepreneurs. Utilities are required to build interconnection facilities to such facilities to connect them into the utility's grid. Furthermore, utilities are requried to pay these qualifying producers the "full avoided cost" of the power they produce, as determined by the state utility commission.

Given today's changed electricity supply and demand situation, however, I question the appropriateness of providing such generous economic benefits to qualifying producers under PURPA in a predetermined, rigid fashion. One can argue that the true "avoided cost" for a utility confronting a substantial surplus of firm capacity over a five-year period is zero, or something close to it. The state regulators face a heavy responsibility as they attempt to interpret Congressional intent under the PURPA during this period of electric power surplus. I am anxious to learn from these hearings how the state utility commissions have implemented the avoided cost methodologies in establishing a price for PURPA producers.

Fundamentally, it seems to me that we have to reassess the value of encouraging non-central station sources of generation as we have done under PURPA. Considering the expense and risk of constructing central station plants today, are the incentives that we offer PURPA producers overly generous? What kind of an economic price tag should society put on this form of decentralized generation? Due to the huge financial risk involved with a 10 to 15 year leadtime, utilities appear to be moving in the direction of acquiring smaller resources with shorter lead times over the next decade. Is PURPA necessary to further this trend? And what about other non-central station resources, succh as greater efficiencies and better load amangement, that don't enjoy the PURPA incentives?

Furthermore, I have a strong concern over the serious environmental consequences of small hydro development stimulated under PURPA. There has been a rush of appplications for licenses and permits for small hydro development under PURPA law. This has been especially acute in the Pacific Northwest. I don't believe that it was the intent of the Congress to encourage a rash of ill-considered new hydro projects on our nation's free-flowing rivers and streams that would cause serious damage to the recreation fish and wildlife resources in these rivers. This Committee has already dealt with the issue partially on the hydro relicensing bill that recently passed the Senate and is now going into conference. But I hope that we can get a fuller and more comprehensive picture of this issue during these hearings.

There may well be some legislation that emerges from these hearings. At this point, I suspect that it would be more in the nature of refining some of the rough edges of the PURPA law than a dramatic overhaul of the law. But I may be persuaded otherwise during thewse hearings. If we are going to begin amending the Fuel Use Act on the restrictions on the burning of natural gas in powerplants, we may as well wish to consider the incentives and disincentives offered to other forms of generation at the same time.

I thank the Chairman for his chairing these hearings and I look forward to receiving the testimony together with him from our witnesses.

Senator NICKLES. Thank you, very much. I share your thoughts about the need for us to use effective oversight on some of the existing legislation that we have, and whether it be PURPA or the NGPA, or other issues that we are working on, I think it is important that we review those and make changes if the facts warrant those changes.

This hearing will focus on three basic questions: First, to what extent have the basic goals of PURPA been achieved? Second, what new problems have been created, particularly those involving the issue of fairness to electric utility ratepayers. Third, to what extent are those problems self-correcting? That is, have the States displayed an ability to respond to changing circumstances and modify their requirements accordingly, thus perhaps obviating the need for corrective legislation at the Federal level.

If our panelists would come forward, we will get started.

The first panel, Mr. D.E. Simmons, group vice president, Houston Lighting & Power, also representing the Edison Electric Institute; Logan Lanham, senior vice president, public affairs, Idaho Power Co.; Calvin Hebert, senior vice president, operations, Gulf States Utilities; and Michael Peevey, executive vice president, Southern California Edison Co.

Mr. Simmons.

STATEMENT OF D.E. SIMMONS, GROUP VICE PRESIDENT, POWER OPERATIONS, HOUSTON LIGHTING & POWER CO., ON BEHALF OF THE EDISON ELECTRIC INSTITUTE

Mr. SIMMONS. Thank you, Mr. Chairman. We appreciate the opportunity to be before you today and to address the questions that you have just laid out.

I am Gene Simmons of Houston Lighting & Power and will be speaking to you with regard to our experience at Houston Lighting & Power in cogeneration, and also as a spokesman for the Edison Electric Institute.

With me today on this panel, also representing the buyers of cogeneration, is Logan Lanham, from Idaho Power, Mr. Calvin Hebert, Gulf States Utilities, and Michael Peevey, from Southern California Edison.

Some of us will be speaking about unique situations that apply only to our own utilities; others of us will be speaking on aspects that apply generally to most of the utilities in the United States.

I do hope that the record will be kept open so that we may have an opportunity to submit some written comments on some of the testimony that will come before your committee later on.

Cogeneration is one of the most critical issues at Houston Lighting & Power Co., and to emphasize that, we have paid some $1.5 billion for cogenerated power in the past 4 years, representing some 32 billion kilowatthours of energy from cogeneration.

Today, on the Houston Lighting & Power System, we have 3,000 megawatts of cogeneration in operation, and another 1,900 megawatts either under construction, being planned or under study. That is some 4,900 megawatts of generation on a system that has a load a little over 11,000 megawatts. So we certainly are inundated with cogeneration.

But our expertise comes from this cogeneration being thrust upon us and we have had an experience with the rapid proliferation of the cogeneration, these units installed by the large industrial companies along the Houston ship channel and the Texas gulf coast. I feel that we do have something to contribute to this policy review, and particularly with regards to the problems we faced and the challenges we see that are still ahead.

A number of these serious problems have surfaced in Texas and grave implications, not only for our customers, but for the customers of the other electric utilities throughout the country.

We are particularly concerned with the way cogeneration has developed in the gulf coast area, and when we talk about cogeneration there, we are not talking about wind, solar, and other energy producers who generate small amounts of power to meet their own needs and then sell whatever surplus is available to the local utilities.

We are talking about the Fortune 500 industrial corporations, who, by virtue of tax advantages and the fall in gas prices, got into the business of selling electricity for enormous profits rather than simply generating the power they need to meet their own needs.

These cogenerators occupy an artificial niche in the marketplace created solely by the legal requirement that utilities must buy all power offered to them by the qualifying facilities. No other business in America enjoys a guaranteed market for any volume of its product irrespective of the demand and regardless of whether or not it can find a willing buyer.

In the HL&P service area there are many large cogeneration units producing hundreds of megawatts of power in excess of the needs of these facilities. However, because of the irresistible profits available to cogeneration from the guaranteed sale to utilities of unlimited amounts of power, chemical companies and other industrial concerns have become almost pseudoutilities.

They are clearly in the business of generating and selling electricity for unregulated profit without any corresponding obligation to serve.

Some say that this partial deregulation of electric generation is desirable. And that may well be, provided that the other consumers on the system are protected. Unfortunately, today there is no such protection for other customers, and the upshot is that the residential and small commercial consumers have to pay higher rates to subsidize cogenerators' guaranteed sales, to accommodate the loss of the large industrial customers from the system, and to maintain the fixed costs associated with the operation of the system.

This is tantamount to imposing a mandatory subsidy on small commercial and residential customers, to finance the windfall profits for the large industrial cogenerators.

I can summarize, that in your evaluation of the role that cogeneration should play in our Nation's electric mix, I would urge that you give serious consideration to the following recommendations which we believe to be crucial to the efficient development of our Nation's electrical power system.

First, regulation of prices utilities pay for cogenerated power is essential to ensure that consumers realize the benefits of cogeneration. This can take the form of rate regulation, discounts from avoided costs, or a redefinition of avoided costs formulas.

In fact, in Texas, consumers are required to pay lignite prices for gas-fired cogeneration, which is not only providing a windfall to cogenerators that customers should share, but is also reducing the long-term reliability of the system.

Second, stricter efficiency standards must be applied to qualifying cogeneration facilities in order that potential energy savings are in fact achieved. We are seeing facilities being built whose overall energy use efficiency is in the lower 40-percent range. We recommend that the overall energy use efficiency standard be raised to 70 percent.

Third, cogenerators should be required to maintain adequate fuel reserves, including a backup fuel supply for the life of the facility to ensure that the goal of fuel diversification is met.

And lastly, mechanisms to certify qualifying cogeneration facilities, based on need, must be established by the appropriate State regulatory agencies so that the utility ratepayers are not required to subsidize the construction of unneeded cogeneration units.

Mr. Chairman, I had not intended to address the broader aspect of transmission access, feeling this was not covered in the scope of this hearing. However, I do note that later on there is some comments on transportation access, and I would like to make a comment regarding that.

The prospect of allowing cogenerators access to utility transmission systems for in-use wheeling has some dire aspects for our customers. We have been wheeling power from cogenerators to utilities in the Electric Reliability Council of Texas for some time and we have among the most liberal and the lowest cost wheeling rates, encouraging wheeling from cogenerators to utilities.

This comes about because we have a large concentration of cogeneration in the Houston area and we need to move that to other areas of the State. However, wheeling from cogenerators to end users constitutes a special interest power wheeling and if allowed, will increase the rates dramatically for other customers on the system.

I urge that Congress resist the pressure to allow the cogenerators to utilize special interest power wheeling.

Gentlemen, obviously, some of these recommendations are appropriate for implementation at the Federal level, and others are perhaps more suitable for action by State regulatory authorities. However, I sincerely hope you will consider them in your review of the role that cogeneration should play in our electric supply mix.

Thank you for the opportunity to be here, and I will be glad to address any questions at the proper time.

[The prepared statement and supplementary testimony submitted by Mr. Simmons follow:]

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Testimony of D.E. Simmons,
Houston Lighting and Power Company

on behalf of

the Edison Electric Institute
before the
United States Senate Committee on
Energy and Natural Resources

June 3, 1986

TESTIMONY OF D. E. SIMMONS
BEFORE THE
UNITED STATES SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
JUNE 3, 1986

I. Introduction

Good morning ladies and gentlemen. My name is Gene Simmons. I am the Group Vice President -- Power Operations for Houston Lighting & Power Company (HL&P). It is an honor and a pleasure to be here today. I am speaking not only on behalf of my company, but also on behalf of Edison Electric Institute, the association of America's electric companies.

Before I address the specific concerns of this committee, I would like to state that cogeneration is a critical issue to our company. HL&P's consumers have more to gain or lose from cogeneration than any other group in the country. Houston Lighting & Power serves a population of over three and a half million people in 158 cities and towns throughout our 5,000 square-mile service area. In terms of kilowatt hour sales, HL&P is the seventh largest individual, investor-owned utility in the nation. Total usage by our 1.3 million customers in 1985 was almost 56 billion kilowatt hours, of which 15% was contributed by cogeneration.

HL&P is probably the largest purchaser of cogenerated power in the U.S. During the years 1982 to 1985, HL&P purchased 32 billion kilowatt hours from Qualifying Facilities

(QFs) and paid about $1.5 billion dollars to cogenerators for this power. In addition, the Company is presently purchasing 820,000 kilowatts of cogeneration under three ten-year firm capacity contracts, and HL&P will wheel over 1,200,000 kilowatts out of our service area to other utilities in Texas this summer.

Furthermore, the Company could be purchasing up to 850,000 kilowatts of additional as-available power from cogenerators this summer, with the actual amount varying depending on economics of the transaction. Our experience has given us special insight into the impact of cogeneration on utility systems and whether the original intentions of PURPA are being fulfilled.

II. Background

The legislative history of Title II of the Public Utility Regulatory Policies Act of 1978 (PURPA) shows that Congress was responding to a diverse set of concerns when it enacted Sections 201 and 210 relating to cogeneration and small power production. These concerns reflected a desire to encourage development of certain types of alternative power supplies (referred to as "qualifying facilities" or QFs) as a means of improving the overall efficiency of electric power supply.

The essential purposes of PURPA were to encourage:

(1) Conservation of electric energy.

(2) Optimization of the efficiency of use of facilities and resources by electric utilities.

(3) Equitable rates to consumers of electricity.

All three of these goals were thought to be equally important, with the result being ratepayer benefits. Under the statute, the rules adopted by the FERC should be consistent with these original goals. Unfortunately, in the desire to promote the maximum development of cogeneration and small power production, implementation efforts have sometimes ignored this concern about the ratepayer. HL&P and EEI believe this problem can and should be corrected through regulatory action, without need for legislative changes.

Before PURPA existed, Congress perceived several obstacles to the development of alternative energy sources: (a) reluctance of some utilities to deal with nonutility generators, (b) the difficulties encountered by project developers in obtaining purchase rates which made such projects economically attractive, and (c) the unwillingness of potential project developers to be regulated as "public utilities."

Title II of PURPA included provisions which were presumably designed to lessen some of these perceived obstacles to QF development. Under section 210 of PURPA, utilities must offer to purchase electricity from QFs at rates which do not exceed "the incremental [avoided] cost to the utility of alternative electric energy" (hereinafter referred to as "QF purchase rates") and to provide backup service to QFs at rates that are both "just and reasonable to the consumers of the electric utility" and in the "public interest" but do not discriminate against QFs. Section 210 also provides FERC with discretionary authority to exempt QFs from state regulation of rates and financial activities, and from federal regulation under the Federal Power Act and Public Utility Holding Company Act. Electric utilities were also required to interconnect with qualifying facilities and must offer to operate in parallel with them under reasonable terms and conditions, consistent with reliable system operation. These benefits were available to projects meeting the requirements established by Congress in Section 201 relating to allowable fuel use, minimum operating and efficiency standards (for cogenerators), maximum facility size (in the case of small power producers), and limits on utility ownership. The implementation of Sections 201 and 210 was subject to rules to be promulgated by the FERC and the state regulatory commissions.

Those are the specific goals and provisions of PURPA. It was hoped that PURPA would defer capital needs for new large central-station generating plants, which are capital-intensive and have long lead times, and would therefore reduce costs to consumers. It was hoped that PURPA would foster our national goal of reducing reliance on scarce fossil fuels. It was hoped that the ratepayers would share in the immediate economic benefits of these alternative technologies.

While PURPA has undoubtedly been successful in encouraging the development of more cogeneration and small power production capacity than would have been developed without its incentives and related tax benefits, most of the benefits of these efforts have accrued to project developers. In most cases it is difficult to see how ratepayers are better off as a result of PURPA implementation efforts. This is illustrated by the development of cogeneration in our company's service area.

III. The Experience on the Houston Lighting & Power System

On the Houston Lighting & Power system when we talk about cogenerators, we are not talking about independent wind and solar energy producers who generate small amounts of power from renewable sources. We are talking about large industrial companies who, by virtue of tax advantages and declining natural gas prices, have become major suppliers of electricity, rather than simply using what would otherwise be wasted thermal energy to generate electricity as a by-product of an industrial process.

These cogenerators occupy an artificial niche in the marketplace created solely by the legal requirement that utilities must buy all power offered to them by cogenerators. To my knowledge, no other business in the country enjoys a guaranteed market for any volume of its product irrespective of demand and regardless of whether or not it can find a willing buyer.

The role of cogeneration and independent power production as it relates to the duty of the utilities to plan for and serve the demand for electricity over the long term is a complex and crucial matter which deserves your closest consideration. There are a number of very serious problems which have surfaced in our service area in this regard, and which have grave implications not only for our ratepayers but also for customers at all levels throughout the country.

At HL&P, we support the underlying philosophy that spawned PURPA and the resulting rebirth of the cogeneration industry because it improved efficiency and conserved natural resources as well as reduced our massive construction program. But in the case of PURPA, philosophy is one thing and reality has proved to be quite a different matter.

In our experience, cogeneration can result in the more efficient use of declining resources. And it can significantly benefit both industrial steam users and the electric utilities. However, the direction in which the cogeneration industry seems headed is more cause for concern than confidence.

It's no secret that many cogeneration facilities reflect a significant distortion of the original intent of PURPA. For example, a 445 megawatt cogeneration facility is planned for our service area. This facility will use 7 times as much fuel as is necessary to meet the thermal output requirements of the facility. Typically, a 37-megawatt gas turbine with a heat recovery boiler could provide the process steam needs of the facility.

In fact a distortion of the National Energy Act has created a "windfall" for large gas-fired cogenerators while threatening to choke off further growth of a diversified full base for electric power production. This windfall results because federal legislation allows industrial use of gas in turbines while at the same time prohibits utilities from building combined cycle plants.

PURPA assumes that a utility will purchase QF power at a price which, for firm capacity purchases, is related to the utility's avoided cost of new capacity. In HL&P's service territory the difference between the cogenerator's cost of producing the power with natural gas-fired equipment and the coal- or lignite-based avoided cost payment results in a subsidy which flows directly from small electric consumers to a few large special interests.

The problem of the subsidy of large cogenerators by residential and other small consumers could be alleviated by insuring that the avoided cost paid to cogenerators is not greater than the cogenerator's cost of building a plant.

Nor is this the only advantage cogenerators have over utilities in building generating capability. Tax laws have permitted cogenerators an accelerated depreciation rate which is not available to public utilities. This advantage is in no way reflected in electric rates and does not flow through to consumers.

Federal policy should reverse the implicit assumption in current regulations -- the assumption that incentives should be provided to cogeneration as long as ratepayers are not harmed -- and adopt a more consumer-oriented position that strives to maximize the benefits to ratepayers without discouraging cogeneration.

IV. Specific Issues in PURPA Implementation

EEI believes that PURPA, if implemented correctly, can contribute to the efficient development of alternative energy and ultimately benefit consumers. I will address the specific problems in the implementation of the statute, and will suggest regulatory solutions which we believe can accomplish the goals of PURPA without the need for substantial changes in the statute. Based on the experiences which utilities have had with PURPA development, after eight years of regulation in this area at the state and federal level, EEI recommends the following specific actions, which require no more than effective enforcement of existing law:

1) In purchasing power from QFs, utilities should not be required to pay more than the cost which it truly avoids. This standard, defined as the full avoided cost standard by the FERC, provides the ceiling rate for QF development, which was originally designed by Congress to ensure equity to the utility's ratepayers. An issue arising in the implementation by the various states has been the precise meaning of full avoided cost, including the issue of whether a utility is required to provide a payment for delivered capacity even if that utility does not have a need for capacity.

EEI encourages FERC to adopt a policy statement reaffirming that the federal authority under Section 210 does not contemplate setting rates in excess of full avoided cost as a basis for "encouraging" QF development. That policy statement should also reaffirm that a utility should not be required to pay charges for capacity which the utility does not need.

2) Rates for power or capacity which a utility sells to a QF for backup purposes should not discriminate against the QF or against the utility's other customers. Therefore, the utility should be fully compensated for the costs of providing this service, just as it would be by any other customer.

3) The FERC should insure that qualifying status is granted only to those facilities which will provide meaningful contributions to conservation and the efficient use of resources. To achieve this important purpose may require two regulatory changes.

First, the FERC should publish more information in its notice of QF application, to allow for meaningful public participation in the certifying process. We believe this can be done without imposing any new burdens on potential qualifying facilities.

Second, in order to avoid the proliferation of machines with marginal or no increased productive efficiency, the qualifying standards themselves should be reviewed. Operating and efficiency standards should insure that a QF project will actually contribute to the fundamental goals of PURPA. Once again, this can be done without any further legislative change.

V. PURPA Implementation Concerns

Let me now turn to some of the specific concerns and recommendations of investor-owned utilities regarding the implications of PURPA. These concerns relate to avoided costs, backup rates for service to QFs, effective standards for qualification of facilities, and the electric utility's role in the efficient development of new resources.

A. The Avoided Cost Issue

The first set of problems arises from the implementation of the full avoided cost rule. If that rule were properly applied, the rates that are paid to a QF would not exceed the true costs which the utility avoids by purchasing this power. That is what the statute says now, and we support that limitation. If that rule is administered badly, not only will ratepayers suffer in the short term, but everybody will suffer in the long term, because the cogeneration industry will develop in an inefficient manner.

The avoided cost ceiling is designed to insure equity to ratepayers, the third goal of the statute. That goal is fairly obvious: ratepayers should not have to pay more for this inexpensive, alternative energy than they would have to pay for the avoided energy and/or capacity. Indeed, there are substantial benefits to cogenerators which were not envisioned when PURPA was enacted, and it is not unreasonable to suggest that the benefits should now be shared between cogenerators and consumers by establishing payment levels at less than avoided costs.

Ratepayers cannot be indifferent to the adequate enforcement of the avoided cost standard, because this standard is preventing them from benefitting directly from cogeneration through lower electric prices. The result of "improper" methods used to calculate avoided costs is a net subsidy to project developers from utility customers. This has the effect of increasing customer bills and stimulating the development of otherwise uneconomic QF projects seeking to exploit a combination of ratepayer subsidies and the various federal and state tax benefits available to QFs.

In an effort to stimulate the maximum amount of cogeneration and small power production, some states appear to have overlooked the important goal of PURPA of equity to ratepayers. They have done this by requiring utilities to pay QFs rates for energy and capacity which exceed the utility's true avoided costs.

States have been able to set rates above avoided costs by a number of different mechanisms, most of which involve long-term contracts. For example, if a state forces a utility to sign a fixed rate contract, by which the utility has to pay a fixed rate for QF power over a number of years, that rate will be higher than full avoided costs if the cost of fuel or other generation costs go down. The same is true if the state sets a "floor" on rates to QFs generally, and true avoided costs fall below that floor. A variation of this problem occurs in so-called "front-end loaded" contracts, by which the utility pays a very high rate, deliberately above full avoided costs for the first years of the contract and a much lower rate thereafter. The rationale in those cases is that the rates will even out over the life of the contract, so that the average rate is below avoided costs; the result is that the present generation of ratepayers winds up subsidizing both the QF and future ratepayers. These problems illustrate the potential for abuses of the avoided cost standard, and work to the detriment of consumers.

The controversy surrounding the proper method for computing avoided costs could be mitigated if FERC provided more specific policy guidance to the states to address many of the conceptual problems and issues regarding avoided cost determination. We believe that it could also have adopted a more active role in adjudicating complaints concerning state rules governing utility purchases from QFs -- as distinct from the "hands off" policy it has manifested thus far.

To reiterate, these problems can be remedied without any legislative change. Instead, EEI recommends the following action:

1) The FERC should adopt a policy statement reaffirming that federal authority under Section 210 does not contemplate setting rates in excess of full avoided costs.

2) The FERC should adopt specific revisions to its rules promulgated under PURPA Section 210 to correct some of the most flagrant and common abuses perceived at the state level, or as a minimum should consider initiating a Notice of Inquiry seeking comments on the efficacy of those rules.

3) The FERC or DOE should voluntarily publish "guidelines" on avoided cost determination to supplement existing rules and addressing issues not considered when the initial rules were promulgated.

4) The FERC should collect and review the various implementation schemes developed by the states under Section 210.

5) In addition, it is HL&P's opinion that the goals of PURPA in serving the public interest can be better met by granting QF status to natural gas-fired cogeneration projects contingent on a showing by the cogenerator that the project has proven reserves and a backup fuel source for a term equal to the life of the project.

B. Rates for Service to QFs

Section 210 of PURPA also requires utilities to sell electric energy to QFs, and commands the FERC to adopt rules to "ensure" that the rates for sales to QFs "shall be just and reasonable and in the public interest" and shall not discriminate against QFs. In practice, however, if utilities are required to sell backup and supplementary power to QFs at noncompensatory rates, it would be detrimental to the utility's other ratepayers. Such a result runs contrary to the public interest.

EEI believes that rates for sales to QFs should reflect the true costs of providing such service. This cost should include payment to the utility for maintaining a spinning reserve, a portion of administrative costs, and an operating and maintenance component associated with the reserve margin necessary to provide reliable service.

C. Operating and Efficiency Standards for Cogenerators

In the case of cogenerators, as opposed to small power producers, it is important to remember the fundamental goals of PURPA: to promote conservation and efficiency, and therefore reduce our reliance on imported oil and natural gas. In fact, most cogenerators burn oil or natural gas, and therefore actually increase our reliance on those fossil fuels. The benefit from cogeneration is of a different type: true cogenerators employ a dual use of the steam, once to produce electricity and once again for some other legitimate purpose. This dual use of steam conserves energy. The FERC was directed to make rules insuring that cogenerators meet efficiency standards to promote that conservation. Such rules were adopted, but are enforced so that the goals of PURPA are being undermined.

Under Section 201 of PURPA, cogeneration facilities must satisfy certain operating and efficiency standards to be eligible for QF status. The FERC's rules define a cogeneration facility as "equipment used to produce electric energy and forms of useful thermal energy, such as heat or steam used for industrial, commercial, heating, or cooling purposes through the sequential use of energy." The Commission viewed its sequential use requirement as a critical characteristic of a cogeneration facility, even though it was not specifically required by the statutory definition of cogeneration.

In addition to requiring the "sequential use of energy," the FERC also imposed minimum operating and efficiency standards (e.g., 5 percent of the cogenerator's output must be in the form of "useful" thermal energy) to avoid qualification of "token" facilities that would produce trivial amounts of either useful heat or useful power, simply to take advantage of PURPA benefits. The FERC's stated purpose in imposing these standards was to "achieve meaningful energy conservation." As a result of several recent FERC decisions, however, it is questionable whether that objective is being met.

As noted above, the FERC's rules define a cogeneration facility as one which uses energy sequentially to produce both electricity and useful heat. However, an increasingly frequent characteristic of some cogeneration systems seeking QF status is the inclusion of an extraction condensing steam turbine, in which large amounts of power are produced without sequential use of the steam (i.e., steam is extracted from the turbine for a nominal heating purpose). An increasing number of cogenerator applications for QF status are employing extraction turbines in arrangements where the clear objective is to achieve maximum electric production with a minimum degree of waste heat utilization contrived to satisfy the 5 percent operating efficiency standard. Such facilities are not substantially different from certain types of conventional utility power plants which are not eligible for QF benefits, and arguably do not conserve energy in the way that PURPA intended.

In a Texas Industries, Inc. (TXI) case the FERC recently decided this issue in favor of granting QF status to a coal-fired cogeneration facility using an extraction turbine, notwithstanding the facility's failure to meet the "sequential use" rule. The significance of the TXI decision goes beyond the two units of this type contemplated by TXI. At a minimum, it applies to a number of other QF applications filed with the FERC with a combined capacity into the millions of kilowatts. The FERC decision appears to open the door to a variety of questionable cogeneration projects whose design appears oriented solely towards obtaining QF status. In the TXI context, no efficiency requirements were applicable because the facility is coal-fired. This left only the "sequential use of energy" requirement, and the operating standards of the regulations, which require that a minimum of 5 percent of the useful energy output be in the form of thermal energy. Even this minimal efficiency requirement was just barely met by the TXI facility.

The FERC's decision in Texas Industries, Inc. was subject to considerable criticism from a number of sources, including utilities and even some QF advocates, who expressed considerable doubts that Congress had ever contemplated granting this type of facility QF status when it enacted PURPA. While not providing any explanation for its decision (that the sequential use requirement only applies to energy used in the thermal process) the FERC appeared to be anxious to avoid the potential need for examining the engineering configuration of each project in detail to determine its compliance with the sequential use standard.

Furthermore, the decision in Texas Industries, Inc. also suggests that the "optics" of appearing to encourage cogeneration took precedence over a more literal reading of the statute which would have denied QF status for the "downstream" portion of the project's capacity. Indeed, the TXI decision would suggest that just about any form of nonutility generation meeting the statutory size and fuel restrictions could qualify for QF status with some token thermal use -- irrespective of the net energy savings achieved over comparable utility-owned generating facilities.

A subsequent FERC decision in the Electrodyne Research Corporation case attempted to clarify its policies on the "5 percent rule" governing the portion of thermal output that must be "economically useful" for the overall project to be eligible for QF status. The FERC found that to be deemed useful, the thermal output of a cogeneration project "must have an independent business purpose with some economic justification," acknowledging, however, that "there is no hard and fast test" for establishing such a purpose.

The result of these decisions, and of the lenient standards themselves, has been the proliferation of so-called "PURPA machines." The label has been given to projects that are essentially oil- or gas-fired power plants, with a small thermal application tacked on to obtain QF status. The label "PURPA machine" derides the statute unnecessarily -- the statute is fine on this point. The problem is that these are not PURPA machines -- they do not further the goals of PURPA and do not conserve energy. The FERC's rules should insure that these machines are not rewarded with PURPA benefits. The result of FERC's lax thermal efficiency standards is that conservation of fossil fuels is not being maximized, and the cogeneration projects which are only marginally more efficient than utility facilities are eligible for PURPA's incentives.

The FERC first should examine its rules to insure that these projects do in fact conserve energy. The rule requiring sequential use of steam should be reaffirmed and enforced. Secondly, the rules should require a legitimate, substantial use of steam for purposes other than production of electricity. When a project simply invents a thermal use for the steam, where no real demand for steam would otherwise exist, no energy is being saved at all. FERC's rules should reflect that fact, and should deny PURPA benefits in such a case. One method to insure that QFs do indeed meet objectives of PURPA in conserving energy would be for FERC to evaluate the overall energy efficiency of a QF under a published standard which sets forth clear energy conservation goals.

The second regulatory action is procedural, and involves the need for greater information about QF projects. EEI does not suggest any expansion of the filing requirements for QFs. The data contained in those applications is sufficient; the problem is that the notices published by the FERC provide such meager information about a filing that it is impossible to tell whether a potential QF is legitimate or not. For example, the notice of a QF application often does not contain any data about the size of the thermal output, precisely what that output will be used for, the identity of the steam purchaser, the utility which will be expected to purchase the power, the size of the project's own demands for electricity or natural gas, and other information necessarily for a utility, state commission or other party to determine whether it should inquire as to the legitimacy of the project's claim to QF status. This data is already in the QF application, and the FERC simply needs to publish it in the Notice of Application, which can be done without placing any new burden on the applicant. Once this step has been taken, the FERC should then encourage increased public participation in the QF process, in order to discourage the development of projects which serve no purpose other than to take advantage of PURPA benefits, and which undermine the stated goals of the statute.

Finally, the FERC should provide some oversight and follow-up of certified facilities to determine whether certified QFs have actually gone into service and continue to meet the goals of PURPA. The lack of actual FERC data about the amount of QF capacity which has actually gone into service creates planning uncertainties for utilities, which now are forced to depend on these projects as firm sources of supply. We understand that the FERC has recently taken positive steps in the direction of collecting such information. We truly hope that it will be made available to the public in order to address these concerns.

VI. Conclusions

To summarize, EEI and HL&P support cogeneration development which will provide net savings in resource usage, providing that benefits flow to consumers without reducing the quality of service. We believe that cogeneration projects which benefit one group at the expense of another will not be successful in the long term. Successful projects are those in which cogenerators and utilities cooperate and work towards ensuring that the objectives of PURPA are met. They are projects where everyone benefits -- the cogenerator, the utility and the consumer. We believe these goals can be achieved through vigorous enforcement of existing law by state and by state and federal authorities. EEI also believes that the maximum efficient development of these alternative energy sources requires that electric utilities be permitted to participate in the development of cogeneration and small power production facilities.

SUPPLEMENTARY TESTIMONY OF D. E. SIMMONS
HOUSTON LIGHTING & POWER COMPANY

BEFORE THE
UNITED STATES SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES

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SUPPLEMENTARY TESTIMONY OF D. E. SIMMONS
HOUSTON LIGHTING & POWER COMPANY

RETAIL SALES AND SELF SERVICE WHEELING

Cogenerators are currently producing electric power for use at their generating plant sites and for sale to electric utilities. The power purchased by the utilities is wheeled, or moved from the generating plants using utility-owned transmission an distribution systems, and resold by the utilities to their other customers. Recent developments indicate that cogenerators are attempting to expand their cogeneration activities through two other forms of wheeling--retail sales to end users and self service wheeling. Retail sales to end users involve the sale of cogenerated power by a cogenerator to a third-party retail purchaser. In self service wheeling, the cogenerator wheels power from the generating site to its other facilities. Both concepts are detrimental to the majority of utility customers and contrary to the principles of public utility regulation.

The potential candidates for retail sales and self service wheeling are large, high load factor power users, a utility's most desirable customers. The industrial load displacement that would result if these cogeneration arrangements were allowed would impose a significant burden on small residential and commercial power users. As firms discontinue purchasing utility-generated electricity, kilowatt hour sales are reduced. An effect of this reduction is that a greater proportion of the system's fixed costs must be absorbed by remaining customers, who would experience rate increases without receiving increased service or benefit.

The approval of retail sales and self service wheeling by regulatory authorities would lead to direct competition between regulated utilities and unregulated cogenerators for large, high load factor users and the significant revenue base they represent. The resulting piecemeal competition would place a serious burden on other utility customers because of the utility's obligation to serve. From an economic standpoint, competition of this nature differs significantly from competition among unregulated entities. Utilities are required by law to serve all customers in their certificated areas on a nondiscriminatory basis; however, this fundamental obligation of electric utilities does not apply to cogenerators whose entry into and exit from power generation are based on financial returns. The proper role of cogeneration is not to serve as direct competition to regulated utilities through retail sales to large, high load factor customers and self service wheeling, because the regulated utility retains its legal obligation to stand ready to serve these customers if the cogenerator stops supplying power. The utility is also legally obligated to provide back-up, standby, and supplemental power to these users, although these capacity requirements may never be used for those customers. The costs incurred in providing these services would be passed on as embedded costs to the utility's remaining customers, and small users, who are unable to take advantage of cogeneration arrangements, would become responsible for the cost of power supply reliability to large commercial and industrial users.

Retail sales and self service wheeling also adversely affect the ability to forecast power requirements. A utility's rates and costs are largely determined by the types of load it serves and the growth of certain load types; therefore, facilities are planned and built to serve different types of customers with diverse load patterns in a manner which allows maximum efficiency in the use of these facilities. Incorporating load diversity into the system results in lower operating costs for the entire system than could be obtained if separate generation was used to meet the maximum demand of each type of customer independently. Elimination of this diversity would result in higher operating costs for the utility's customers.

Cogeneration retail sales and self service wheeling also negatively impact the revenue production capabilities of state and municipal governments. Electric power purchased from utilities is subject to franchise and sales taxes levied by state and local governments. Reductions in kilowatt hour sales would decrease these sources of public revenue. The fiscal impact on cities that own utilities would be even more detrimental because they use revenues from kilowatt hour sales to fund other municipal services. These tax revenue losses could ultimately lead to reduced government services and/or shifts of the overall tax burden to other taxpayers.

These cogeneration arrangements are also contrary to the regulatory oversight function of the state and municipal governments. Regulatory authority over the generation of electric power would be relinquished as unregulated cogenerated power became available to end users statewide. Cities and towns would also lose their jurisdiction to regulate the electric rates of many large commercial and industrial users. Any possible benefits from this type of deregulation would be received by cogenerators and large electric power users.

The consequences of authorizing retail sales to end users and self-service wheeling of cogeneration extend beyond the generation and distribution of electricity. They affect all electric power users as ratepayers and taxpayers. These arrangements benefit cogenerators and large retail customers. The benefits, however, will be accrued at the expense of most other ratepayers. Because of this inequity, the regulatory authorities should continue to prohibit these two types of cogeneration wheeling.

SUPPLEMENTARY TESTIMONY OF D. E. SIMMONS
HOUSTON LIGHTING & POWER COMPANY

COMPETITION UNDER THE PURPA MODEL

The growth of independent power production under PURPA is raising consideration of whether steps should be taken to encourage competition between those power producers and utilities. Before discussing whether PURPA has encouraged and should encourage greater competition in electric power production, it is important to emphasize that competition is a broader concept than many people realize. It involves not just price competition, but goes to the fundamental differences between regulated utilities and unregulated enterprises. The two principal differences relate to (1) obligation to serve, and (2) profit regulation.

Utilities are said to have an obligation to serve all those seeking electric power service at retail within their service territory. This obligation is consistent with and derives from the exclusive right of the utility to supply electric power service within its franchised service area. The obligation to serve, that is, derives from the grant of an exclusive sales monopoly in the franchise area. As a result of their obligation to serve, utilities have planned their systems based on load projections that include wholesale requirement customers as part of their native loads. There have been few, if any, cases in which utilities have declined to provide requirements service to distributors located generally within their service areas. Service typically has been provided under tariffs or under contracts with the requirements customers whereby the latter agree to purchase all their requirements or specified parts thereof from the supplying utility. Further, utilities have generally supplied power to these customers so long as the customers want it and so long as they are prepared to enter into arrangements which accommodate reasonably efficient planning of bulk power facilities by the utilities.

A competitive firm, like a QF, has no obligation to provide goods or services to customers beyond that which may be contained in contractual arrangements. It can decide whether or not to expand production capacity based on market analysis and projected profitability. Typically it will not decide to do so unless it projects additional sales sufficient for recovery of investment over a relatively few years.

The second important difference between regulated utilities and competitive firms relates to profit limitation. When a competitive firm finds that it has invested in an unprofitable venture, it may have to absorb the entire loss. In some cases, such unprofitable investments may lead to bankruptcy and the dissolution of the enterprise. On the other hand, if the venture proves to be successful, there is no limit on the profits that the enterprise may earn. There is thus a symmetry in that competitive firms may have to absorb the entire risk of a venture, but they also have the right to any and all gains to be derived from it.

By contrast, if there is to be a limit on the profits of regulated utilities, symmetry requires some sharing of the risks. Efforts to achieve symmetry of this sort are reflected in myriads of decisions of regulatory commissions and courts in rate cases at both the state and federal levels.

The notion that PURPA somehow constitutes the initial phase of a more competitive bulk power market is contrary to any reasonable definition of the term "competition." What PURPA does is create a two-tiered market wherein a privileged set of participants (i.e., QFs) are given the opportunity of earning an unregulated return by guaranteeing them a purchaser for the sale of their output at an administratively determined price. In effect, we have "deregulated" a small set of sellers by imposing a new set of regulatory burdens on the buyer. It is difficult to conceptualize this arrangement as constituting a "competitive market" or having anything to do with the economist's notion of competition. QFs have even opposed limited utility efforts to solicit competitive bids in those cases where the supply of QF capacity exceeds the utility's need for power. As the notion of QFs providing a yardstick to measure utility performance and thereby provide an incentive for utilities to improve their performance, such comparisons are totally meaningless until both parties are subject to the same set of regulatory requirements and both are eligible for the same tax benefits, etc. Otherwise, we are back to making the same type of "apples and oranges" comparisons that public power advocates have used for many years. "Yardstick competition" is a questionable concept in theory and is totally irrelevant in practice unless all market participants are operating on a level playing field. This is certainly not the case under the PURPA model.

To summarize, I would like to emphasize again that competition in electric power production is much broader than just price comparison: It also includes factors such as obligation to serve, reliability of service, and a commitment to serve for the long term, all of which are as important to consumers as is the price.

It is clear that the original intents of PURPA -- to conserve energy, increase efficiency in use of resources, and insure equitable rates to consumers -- have been subverted. PURPA has created a two-tiered market wherein qualifying facilities are given the opportunity to earn an unregulated return and provided a guaranteed market, although these qualifying facilities have none of the traditional service requirements.

A comprehensive analysis of all these factors in light of what is in the public interest must be included in consideration of competition in the electric power supply industry.

SUPPLEMENTARY TESTIMONY OF D. E. SIMMONS

TRANSMISSION ACCESS

Wheeling of electricity is a term used to describe the moving of electrical power from one electric system to another over the transmission systems of other utilities.

In order for power to move among electric systems, the transmission lines must be interconnected. There are three networks of interconnection systems, or grids, in the U.S.: the Eastern grid, extending from the Eastern Seaboard to the Plains States; the Texas grid (ERCOT), operating entirely within the state of Texas; and the Western grid, covering the Pacific Coast and the Mountains States. These electrical grids all operate at a frequency of approximately 60 Hertz; however, they are not synchronized.
In order to maintain this non-synchronized operating condition, a grid cannot exchange electrical power with another grid unless the power is transformed through a Direct Current (DC) interconnection.

The Texas grid (ERCOT) covers a large portion of the state. The Electric Reliability Council of Texas (ERCOT) consists of six investor-owned electric utilities (Central Power & Light, Houston Lighting & Power, Southwestern Electric Service, Texas Utilities Electric, Texas-New Mexico Power, and West Texas Utilities Companies), a state agency (Lower Colorado River Authority), and numerous municipalities and cooperatives.

There are six inter-state electric utilities in Texas, four of which -- El Paso Electric, Gulf States Utilities, Southwestern Electric Power Co., and Southwestern Public Service Company -- operate entirely outside of ERCOT. These companies belong to and operate in either the Western System Coordinating Council (WSCC) or the Southwestern Power Pool (SPP). The other two electric utilities which are part of an inter-state system -- Central Power & Light and West Texas Utilities -- operate in ERCOT.

Transmission access means the availability of an electric utility's transmission system to anyone wishing to wheel power. Transmission access and wheeling already exist in Texas in a manner that is beneficial to the general body of ratepayers and take one of two forms -- wheeling between electric utilities, and wheeling between small power production or cogeneration facilities and electric utilities.

The Public Utility Commission of Texas (PUC) has developed a comprehensive intra-state wheeling policy for intra-state utilities within ERCOT. Wheeling for inter-state utilities within Texas is under the jurisdiction of the Federal Energy Regulatory Commission (FERC). The inter-state utilities' wheeling transactions are not governed by the PUC policy.

The most common wheeling arrangement is one in which one utility transfers power to another utility. These transactions occur as a result of contracted purchased power sales, economy power purchases, and conditions precipitated by equipment problems, severe weather, or other emergencies. Wheeling transactions of this type are normally contractual in nature and are addressed for ERCOT utilities in PUC Substantive Rule 23.67. Furthermore, the state granting a cogenerator mandatory access to a utility transmission facility would in essence amount to conscription of private property (transmission lines) by government.

The other form of wheeling in Texas involves the transfer of power from a small power production or cogeneration facility ("qualifying facility") through third-party utilities' transmission systems to a purchasing utility. Wheeling from cogeneration facilities through or from the service areas of other utilities to deliver power to a purchasing utility is addressed by PUC Substantive Rule 23.66. Essentially, this rule constitutes mandatory wheeling for those ERCOT utilities subject to PUC wheeling regulation, and establishes a two-tiered rate structure for non-firm and firm wheeling. Under this rule, non-firm wheeling is interruptible while firm wheeling has the same firmness as the wheeling system's own load.

The two wheeling rules promulgated by the PUC set forth procedures governing transmission access that result in wheeling transactions that are potentially beneficial to all ratepayers. Economic energy transfers between utilities and between cogenerators and utilities can now be transacted more routinely and with more certainty. Recent developments, however, indicate that there is interest by cogenerators in wheeling power directly to end users. This type of wheeling benefits only the supplier and the purchaser involved in the transaction, while the ratepayers in general do not benefit. This type of transaction would require access to existing utility transmission or distribution systems. The concept of wheeling directly to an end user from a cogenerator is contrary to the traditional principles of a utility's obligation to serve all customers within its certificated service area, and the right of the utility to serve customers within that same area.

Wheeling of power to end users generally falls into one of two categories -- wheeling for retail sales to end users, and wheeling for self service. Retail sales to end users, whereby a qualifying facility wheels power over a utility's transmission or distribution system to a third-party retail purchaser, is not consistent with the intent of the Public Utility Regulatory Policies Act (PURPA). The Act, which provided the mandate and impetus for cogeneration and small power production, was promulgated with the intent of having qualifying facilities sell to utilities. There are currently no federal or state laws requiring utilities to wheel for cogenerators making direct sales.

Self service wheeling, whereby a qualifying facility wheels power over a utility's transmission or distribution system between locations owned by the same qualifying facility, was not envisioned by PURPA.

Access to the statewide utility system for the purpose of retail sales by cogenerators, or for self service wheeling from cogeneration facility to another facility owned by the cogenerator, is detrimental to the majority of a utility's customers for the following reasons: adverse impacts on existing utility customers; obligation to serve; and unfair competition.

POTENTIAL ADVERSE IMPACTS ON EXISTING UTILITY CUSTOMERS

A utility's rates and costs are largely determined by the type of load it serves and the growth of certain types of loads. This results in facilities being built to serve different types of customers with different load patterns in a manner which allows maximum efficiency of facilities. For example, the same generator that is being used to serve a business with a peak demand occurring at 4:00 p.m. can also be used to serve a residential load which peaks at 7:00 p.m. and a street lighting system which peaks at 9:00 p.m. A natural diversity exists which results in a lower cost for the entire system than could be obtained if separate generation were required for the maximum demand of each type of customer separately. If a cogenerator is allowed to selectively serve certain high-capacity factor retail loads, the utility's fixed costs may remain unchanged; but, under traditional pricing concepts and ratemaking practices, these costs would have to be paid for by the remaining customers on the system. Allowing cogenerators to serve selective "premium" loads would result in higher costs for the remaining retail and residential customers, who are the very people that traditional public utility regulation protects.

OBLIGATION TO SERVE

Utilities have an obligation to serve all those seeking retail electric power service within their certificated area. Utilities plan their systems based on load projections that include these loads, and are obligated to supply power to these customers as long as the customer desires it.

An unregulated firm has no obligation to provide service. It can decide to expand production capability based on projected profitability of the loads to be served. Typically, it would not decide to do so unless these sales were sufficient for recovery of investment over relatively few years.

If cogenerators are allowed to selectively serve retail loads in the absence of a general obligation to serve, then the utility's obligation to serve should also be limited to that of an unregulated firm. Without this obligation to serve, a utility company would also apply rigorous profitability standards across the board prior to rendering service. An important point regarding a free market system in this respect is that a free entry also implies a free exit. Consequently, no one would have an obligation to the marketplace for providing electrical service.

UNFAIR COMPETITION

Allowing cogenerators the right of mandatory access to the utility's transmission or distribution systems for the purpose of serving retail loads within the utility's certificated service area would make the certificated service area concept meaningless. If cogenerators were allowed to selectively choose retail loads throughout the state, they would completely destroy a utility's basis for facilities planning, which would result in a grossly inequitable competitive situation unless utilities themselves were offered the same option. In the absence of an obligation to serve, a utility could selectively choose retail loads outside its certificated area, reducing the overall costs of that utility at the expense of another utility's customers. This concept of open competition is not in the interest of Texas ratepayers.

The CHAIRMAN [presiding]. Thank you, Mr. Simmons.
Mr. Lanham.

STATEMENT OF LOGAN LANHAM, SENIOR VICE PRESIDENT, PUBLIC AFFAIRS, IDAHO POWER CO.

Mr. LANHAM. Mr. Chairman, and members of the committee, my name is Logan Lanham. I am from Boise, ID. I am senior vice president of public affairs of Idaho Power Co.

I would ask that the full text of my testimony be entered in the record.

The CHAIRMAN. I should have noted at the beginning that the full text of each of your statements will be placed in the record in full.

Mr. LANHAM. Thank you, Mr. Chairman. Also, I have a study from the Boise State University, College of Business, "The Economic Effect of Public Policy Implications of Cogeneration and Small Power Production in Idaho."

I would like to have that placed in the hearing file because it is too voluminous for your record.

The CHAIRMAN. It will be placed in the file.

Mr. LANHAM. Thank you, Mr. Chairman. Idaho Power Co. is an independent, investor-owned utility serving southern Idaho and northern Nevada and eastern Oregon. We serve electric service to 270,000 customers in a 20,000-square mile area.

To illustrate the expanse of our territory in relation to the number of customers, we have 4,600 miles of transmission lines and 17,000 miles of distribution line.

Our company's electrical supplies come primarily from hydro. From 62 to 82 percent of our energy is supplied by 17 hydroelectric projects on the Snake River.

We are also forced to purchase cogeneration and small power due to PURPA. Now, we recognize that all companies are not the same, and the effect of the act—it affects each company individually.

There are members of this committee who were present at the passage of PURPA in 1978, and so to recall some of the things that happened then would be redundant. However, I think it may be well to call to the committee's attention that PURPA was passed in the days of the OPEC, oil embargo, and long gasoline lines, and I am not one to dispute that the intent of the legislation was an important one, but it was passed in haste, and unfortunately, in the urgency of the situation we faced, very little consideration was given to the fact that different parts of the country face vastly different energy supply situations.

As Senator Evans mentioned, out in the Northwest and the West, primarily, we have large amounts of hydro and renewable resources.

Nevertheless, when PURPA was passed, and Idaho was one of the first States to adopt regulatory policies regarding it, it looked like the Klondike. Everyone rushed to Idaho to file on every stream and tributary in the State, and as of May 6, 1986, we had added to our system 47 projects, with signed contracts, which was over 83,000 kW.

Now, 83,000 kW to 70 percent load factor will furnish 32,000 homes with supplies of electric energy for 1 year on our system, and nationwide, it would be 54,000 homes. We only hooked up 2,300 last year. So, it has a dramatic effect.

Waiting out in the wings to be signed and to come online are 230,000 kW more, which is equal to one of our largest hydroelectric facilities.

Senator **Nickles**. Mr. Lanham, was that all hydro?

Mr. **Lanham**. Most of it is hydro, Senator. We only have what you call cogenerators and those are sawmills that are using wood waste.

Nevertheless, in having to purchase all of that energy, we have been trying to sell some of it offsystem. And we are paying an extremely high price and forced to sell it at whatever the market will bear.

As an example, in one of your exhibits there, I have—and I just took them out of the file; they happen to be May 20, and 21—we were forced to purchase on May 20, 49,000 kW of cogeneration, and at the same time we spilled around the turbines 88,000 kW. Now there is no provisions, as you recall, to allow a utility to cut back on its highest priced energies, which are you qualifying facilities. Not only that, the next day, while we were buying 32,000 kW small generation, small power, we were not spilling anything, however, they dropped in production 17,000 kW, which tells me, and should tell anyone else, that they are not reliable or dependable resources.

Not only that, we were selling that power from 10 to 30 mils and some of the cogeneration we are paying 7 cents a kilowatthour. So it is easy to see why my company is deeply concerned and interested in the need for the modifications and adjustments, amendments, or even the repeal of the Public Utility Regulatory Policy Act.

Now, PURPA has many defects, and I will enumerate them and then later on discuss them. The first is that the utilities are forced to buy, forced to purchase all that cogeneration, even when it is not needed and that causes unnecessary rate increases.

Second, having so many facilities connected to your grid creates a reliability problem.

Also, you have environmental problems, and you have power operation and electrical operating problems. I will cover them briefly if I may.

The major concern is our lack of authority to dispatch a qualifying facility. Most of them don't even have an attendant. They come by once a day, and sometimes once a week, and squirt a little oil in and go on by and if it is running, they don't pay any attention to it. We don't know whether it is on or off. Some of them are more sophisticated than that, but most of them are not.

Just one example, during April 1 to May 20, we received approximately 60 million kilowatthours from QF's; we paid $3 million for it, or 5 cents a kilowatthour. At the same time, we turned around and sold 840,000 megawatthours for a penny. Now, it doesn't take much of that before it has a considerable impact upon your customers. Not only that, it resulted in a loss of $2.4 million to our customers.

It is nondispatchable. You can't turn it off at night when your load drops. You have to turn off your other facilities, such as your coal plants. We are forced to turn those down, where the decremental costs are from 17 to 29 percent of the qualifying facilities. Not only that, FERC has approved certain guidelines, specific guidelines, that you have to have for spinning reserve depending upon your generation—that is a function of your generation. Five percent for online hydro and 7 percent for thermal.

We also question the reliability, as I said before. You have a storm that trips off the line and because our area is so sparsely settled, and our distribution lines are extensive, you can have one line off shooting trouble on it and a qualifying facility pumping power in on the other end. So we have had to design facilities, hopefully, that will work, that won't electrocute our linemen.

However, you never know when they are on or off and when the line does come on, the load is there but you don't know whether the generation is going to be there.

The operating problems are there, as we see it. You have transit voltage, a substation pumping in power on one end and some QF on the other, and you have certain harmonics in the voltage running back and forth. You lack control of the generation and you have no information on what the load is doing or where it is.

Now, a QF is not under any obligation to generate into our system, however they do. Their primary operating directive is make profit, to maximize it. In fact, when they come on the line, they create so much disturbances that we have had to reconstruct many of our facilities.

One, as an example I have given here, we spent over $500,000 just to increase the voltage to accept that facility on our line. Other example, of course, is down on our western division, where Elk Creek generation is 31 miles from the substation. It has created a terrific problem down in that area, which the chairman knows very well about.

Environmental consideration; it is a disaster, in most instances, and there is an exhibit in there showing you the number of facilities that have washed out or had problems.

I think when PURPA was passed, they primarily thought that most of these hydro facilities would be on existing dams or structures, and that is not the case.

What we are concerned about, and others, are the local fisheries. They put them on these streams and there is no passage, and at times there is no water. Our primary concern, of course, and a major concern for our anadromous fish facilities, which are chinook and steelheads.

We have spent $30 million trying to maintain fish hatcheries and enhancing wildlife habitats and providing recreation, and it would seem unreasonable for us that PURPA or anything else could have the disastrous effect that it may have.

Now, I know that they are doing a cumulative impact statement on the Salmon River and its tributaries, but that is only the beginning, because I don't know where it is going to end.

The other thing, PURPA was supposed to be fair, just and reasonable, not only to the QF's, but to the utility and also to the customers who pay the bill. A couple of examples, the Tamarack energy partnership, which is in north Idaho on the northern part of our system; it uses wood waste to generate power and, if you recall, the regulations issued on April 3 by the FERC addresses simultaneous purchase and sale.

Well, we have to purchase Tamarack energy at its avoided cost, all of it, in total, and then we turn around and sell them their requirements back at our average system cost. Now, remember, we are forced to buy this at 7.3 cents a kilowatthour. We turn around and sell it back to them for 3.7 cents a kilowatthour, and the difference of 3.6 is billed to the rest of our ratepayers.

It would appear to me that the other customers on Idaho Power Co. System are paying Tamarack $110,000 to use their own energy, and I would submit to you that this is not just and reasonable and it is not in the public interest.

Another example, you well know, may be the Reynolds Creek Irrigation District. They had a siphon from the top of the hill, down across the river and back up to an irrigation facility that irrigated their lands. Their siphon became perforated because it was worn out. Now, we offered to help them replace that siphon and they turned us down.

What they did was they went and built a hydro, small power producer on one end of of that siphon. They sell us power there for about 7 cents a kilowatthour. They went across the river and built a pumping plant, and I have to sell the power back to them for a little over 2 cents. Now, I don't think that is necessarily in the public interest.

Not only that, it is a 35-year contract.

One other example, and in all due respect to Mr. Simmons—he mentioned it, the Fortune 500—there is Afton Generating Co., Ltd., in Afton, WY. It burns waste wood. It is not in the State of Idaho. It is not in our service area, and yet their prospectus says that this project is expected to yield about 20 percent cash return, which I consider probably fair and reasonable to the investors, each year, for the first 7 years, at which time the debt will be repaid, and then after that, the investors' cash return is expected to go up to 50 percent a year.

That will be for the next 28 years. They say in addition to their strong cash-flow, that the investors will benefit from investment tax credit, energy tax credits, and 5-year depreciation schedules, and collectively, those tax benefits will recover about 70 percent of the investors' investment the first 5 years.

Now, it would appear to me that a nation that has a $2 trillion deficit should discontinue handing out investment tax credits and energy tax credits and 5-year depreciation. We are paying 11.5 cents per kilowatthour for that energy. And at the same time, I am selling energy to my homeowners for 4 cents, or under 4, irrigation customers at 2½ cents, and industrial and the rest of them for between 2 and 2½ cents.

The avoided costs is another point that I would like to address, and there are two or three probably different terminologies, regulations. One of them is, FERC says that the cost—the definition is as the cost to an electric utility of energy or capacity or both which, but for the purchase from a qualifying facility the electric utility would generate or construct itself or purchase from another source.

The two problems associated with that is, first, we are forced to purchase that energy, and as incredible as it seems, the issue is not need. They don't say that you have to need the power. Second, we are required to sign a long-term firm contract at prices that are established by coal-fired plants.

Now, it is true that the Idaho Public Utility Commission has changed cogeneration rates from 4.5 to 4.7 cents, but those contracts, the contracts that Idaho Power Co. has been forced to sign for energy it does not need from those facilities that are generating today will cost our ratepayers $1.171 billion over the life of the contract. I don't think that is necessarily just and reasonable.

The PUC also requires us to sign or give levelized rates for these cogenerators. Now, that is QUIP, in essence, and QUIP is outlawed in the State of Idaho. However, on a 35-year contract, paying more to the customer than he should receive in the beginning, it takes 25 years before that crossover comes, and if they are still in business, you can recoup part of that high cost at the end of—between the 25 and 35 years.

However, you don't know whether they are still going to be in business. We have some of them out there, some of those small hydros that utilize irrigation pumps, setting them on 6 by 2 by 6's and running them backward, and I don't know how long they are going to last and whether they are going to be around.

So, nevertheless, their reliability and their longevity may not be all that great.

In conclusion, I would like to—I guess I would be remiss if we didn't suggest to the Committee and Congress that they reevaluate PURPA and its rules and regulations. One of the possibilities would be to repeal the portions of PURPA relative to small power and cogeneration as they may no longer be of value.

The second would be remove the portion of the act that requires the forced purchase of electricity by the utilities, when the energy is not needed, especially at extremely high rates, and three, make need a requirement before FERC or any other agency can issue a license or permit for small power production or before a developer of a cogenerated facility can qualify for a power sales contract.

Four, place a cap on the avoided costs. I don't know necessarily what that cap would be, but maybe it should not exceed your average system cost or, maybe twice what it is.

Fifth, clarify the option of the utility to obtain additional energy supplies, or give him the option to either construct his own facilities, or purchase energy from cogeneration or small power producers, or purchase energy from other sources.

At least, that would give your customers who are actually paying the bill the reasonable and most likely reliable supply of electrical energy.

Six, allow the revisiting of contracts by defining the term "legally enforceable obligation" as used in the FERC regulations. Today, some utilities are obligated to sign 35-year contracts which have escalators that increase the costs dramatically over the period of the contract. Now, this is neither fair, just, nor reasonable to our customers or to the utilities.

Finally, if you really want to be fair, just, and reasonable to your constituents, you will repeal the investment tax credits, energy tax credits, and 5-year depreciation schedules for cogeneration and small power production.

This list is not necessarily in the priority of importance, but it is a suggestion to the committee for their consideration.

I would like to thank you, Mr. Chairman, and members of the committee for the opportunity to present our views on this issue.

[The prepared statement of Mr. Lanham follows:]

TESTIMONY OF
LOGAN LANHAM
SENIOR VICE PRESIDENT OF PUBLIC AFFAIRS
IDAHO POWER COMPANY

BEFORE THE UNITED STATES SENATE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
JUNE 3, 1986

My name is Logan Lanham of Boise, Idaho. I am Senior Vice President of Public Affairs for the Idaho Power Company. We appreciate the opportunity to present our position and views on the implementation of the Public Utility Regulatory Policies Act of 1978 (PURPA) and its effects upon the Idaho Power Company and its customers.

Idaho Power is an independent, investor-owned utility founded in 1916. It supplies electrical service to 270,000 customers in a 20,000-square-mile area of southern Idaho, northern Nevada, and eastern Oregon. To illustrate the expanse of our territory in relation to the number of our customers, we have over 4,600 miles of transmission lines and 17,000 miles of distribution lines.

Idaho Power Company's customers have been fortunate in the past as the Company has been able to rely heavily on low-cost hydroelectric generation to meet their energy needs. The Company is one of the nation's few utilities with primarily a hydro base. More than 70% of its generation is supplied by 17 plants in Idaho on the Snake River and its tributaries. The Company's hydro plants, because of above-average water, provided 75% of our actual generation in 1982, 82% in 1983, 77% in 1984, and 62% in 1985. The balance of our energy comes primarily from three coal-fired plants in which ownership is shared. We also are forced to purchase cogeneration and small power due to PURPA.

We recognize that all companies are not the same and that the effects of the Act on individual utilities are not uniform throughout the United States. Each utility has its own load and generation configurations. Differences in resources in territories served by each utility affect the number and type of cogeneration and small power facilities each utility must deal with. In our territory the facilities range from very small to rather sizeable hydroelectric projects scattered throughout the system, to wood-burning generating facilities at sawmills.

There are members of this Energy and Natural Resources Committee who were present at the passage of PURPA and to reiterate its history would be redundant. However, I think it is well to call to the Committee's attention that PURPA was passed in the days of OPEC, of oil embargoes and of long gasoline lines. All those things prompted the country to decide to become energy independent.

If memory serves me adequately, the nation wanted a national energy policy, a policy that would reduce its dependence on foreign petroleum supplies. It got such a policy through PURPA and I don't think anyone would dispute that the intent of the legislation was a proper and important one.

Unfortunately, in the urgency of the situation we faced, little consideration was given to the fact that different parts of the country faced vastly different energy supply situations.

For instance, in the West, and more particularly in the Northwest, many electric utilities have little or virtually no reliance on petroleum as a generating fuel. Idaho Power, for example, uses the renewable resource of falling water and the country's vast domestic coal supplies to generate the electricity its customers need. We've always been and continue to be totally free of the need to rely on foreign energy sources.

Nonetheless, PURPA applies to us without any recognition of our circumstances. Idaho was among the first of the states to adopt regulatory policies forcing the purchase of cogenerated and small power facility generation by utilities. Since then there has been a rush to develop cogeneration and small power facilities. As of May 6, 1986, the Idaho Power Company has added to its system 47 projects with signed contracts totaling 82,558 kilowatts (kW). The peak generation for 85 other projects that are in the wings and waiting to have contracts signed and to come on line is 229,996 kW. The total peak generation for all of the projects, those existing and those proposed, would amount to 312,454 kW which is equal to one of our largest hydro facilities. The capacity at peak generation for the 42 projects actually connected and operating on the Idaho Power Company's system is 75,948 kW. The generation output for these projects during the month of April however was approximately 65,000 kW. The average generation for the month of April was 59,297 kW. This will give you an idea of the number of projects, large and small, that are being connected to the Idaho Power Company's system and those that are proposed to be connected. In the aggregate, they are materially burdensome not only to Idaho Power Company itself but to its ratepayers, especially since they are not needed.

The Committee may not be aware that the Northwest has surplus power supplies and could have for a number of years. Idaho Power Company has been selling energy off its system every year because of abundant water to fuel its hydro system and because it has been forced to buy small power and cogeneration it does not need. It is also required to pay an exorbitantly high price for this energy. It's energy we can only sell to other utilities at a low price. Our customers have to make up the difference. They now are paying millions of dollars a year for electricity they can't use. If we are forced to purchase all the proposed generation I mentioned earlier today, the impact on our customers will be disastrous.

As an example, the System Operating Report dated Tuesday, May 20, 1986 (Exhibit I), shows that the Company was forced to purchase 49,000 kW of cogeneration while at the same time we had surplus hydro, or spilled 88,000 kW of generation over the spillways. You may recall there are no provisions in PURPA to allow you to cut back on your highest priced energy, which is the qualifying facilities (QFs) or your cogeneration and small power, but you must purchase it and cut back on your own facilities which produce less costly power. I will address this in more depth later in my testimony.

On Wednesday, May 21, you will note we were buying 32,000 kW of small power and cogeneration. The drop of 17,000 kW in production from the day before illustrates another problem--cogeneration and small power are not reliable or dependable resources.

We are able to sell this energy to other utilities at a price ranging from 10 mills to 30 mills a kilowatt hour. At the same time, we have been required at times to pay cogeneration and small power producers over 7 cents or 71 mills per kilowatt hour. It is easy to see why the Company is deeply concerned and interested in the need for modifications, adjustments, amendments, or even the repeal of the Public Utility Regulatory Policies Act of 1978.

PURPA Has Many Defects

One, of course, is it forces utilities to purchase all power generated by cogenerators and small power producers even if it is not needed, causing unnecessary rate increases. Having numerous facilities connected to the grid creates a reliability problem. Small hydro power causes environmental problems as does wood-burning cogeneration. Numerous small plants create power operation and electrical operating problems. Let me elaborate some of those problems that are particularly troublesome to a hydroelectric company like Idaho Power.

Power Operation and Reliability

One major problem facing Idaho Power Company today is our lack of authority to dispatch QFs. During the spring months when our hydro system is extremely surplus and the majority of our thermal resources are off-line, QFs continue to generate. The energy from these QFs is extremely high in price compared to our other resources and, as such, unmarketable even at cost. Because utilities have no control over the output of QFs, at times like these we are forced to purchase the energy from them and sell it off-system at a loss. To put the problem into perspective, I offer the following example:

> During the period April 1 through May 20, 1986, Idaho Power received approximately 59,400 MWHrs of energy from QFs and paid nearly $3 million for that energy, an average of approximately 50 mills/kWHr. During the same period, Idaho Power made surplus sales in the amount of approximately 840,000 MWHrs at an average price of 9.9 mills/kWHr. The surplus sales were made primarily from excess hydro generation (water was spilled past the majority of our hydro projects during this entire period), thermal displacement that we received from Bonneville Power Administration and QFs energy. Since the purchase price of the QFs energy was considerably higher than the price we received for surplus

> sales, the QFs transactions resulted in a $2.4 million monetary loss to the Company's customers.

Another problem, which is very similar to the first, centers around the basic fact that there is a growing amount of non-dispatchable energy being produced by the QFs that is not needed. This problem is magnified during certain times of the year when there are large fluctuations in system load between the on-peak and off-peak hours of the day. During these periods we have most, if not all, of our thermal resources on-line and generating in order to meet the high peak loads experienced during the day. However, at night, the loads drastically decrease and we must back down generation to follow that load. Reducing only our hydro generation, even to absolute minimums, is not adequate. At this point, basic economic dispatching procedures direct us to reduce the resource with the highest incremental cost. This highest cost resource is the QFs energy. But since we have no control over the QFs, we are forced to back down our coal-fired resources whose decremental costs are from 17-29% that of some QFs energy. Again, this action results in the Company's customers realizing a substantial monetary loss.

As it was implemented, PURPA is causing us another power operations problem. FERC has provided specific guidelines concerning the operation of electric power systems. One of those guidelines details the amounts of reserve generation that must be maintained by utilities at all times. The quantity of required reserve is a function of the amount and type of generation that the utility has on-line and producing power. Within the Western Systems Coordinating Council, operating reserve obligations are 5% of the on-line hydro generation, plus 7% of the on-line thermal generation, half of which must be spinning reserve. As the amount of QFs generation increases, the amount of required spinning and operating reserve increases. In other words, utilities are required to reduce the output of their lower cost resources merely for the purpose of supplying reserve obligations imposed on them by the addition of QFs. Economically, the utility's customers again are realizing a monetary loss because of the reduction of low cost generation for the sake of adding high cost QFs generation to the system.

One more problem, or area of concern, that is affecting our power operations department is QFs reliability. At the present time, the amount of QFs generation on-line is small compared to the amount of our own resources. Therefore, the problem of QFs reliability is not currently too severe. However, QFs generation has been steadily increasing on our system, and this problem will soon become a serious one. QFs reliability affects the power system most noticeably during adverse weather conditions, primarily electrical storms. When strong lightning storms pass through the area, they randomly cause feeder and transmission line outages. Automatic reclosing will quickly restore the load, but the protection packages installed on the QFs do not allow their immediate return. These packages are designed primarily for the protection of Idaho Power customers' equipment. Due to the lack of adequate governor and voltage control equipment on the QFs, the protection packages prevent QFs from generating and serving load in an islanded condition. The result is the load returns, but the generation does not. This occurrence, coupled with other possible system problems, could very likely in the not too distant future result in Idaho Power experiencing a severe system disturbance.

Another problem relating to the interconnection of QFs are the electrical operating problems associated with those facilities.

Electrical Operating Problems Associated with Qualifying Facilities

Three of the more significant operating problems caused by QFs are transient and steady state voltage disturbances, lack of control of generation, and loss of information on system load.

A typical distribution feeder voltage profile has higher voltage at the substation and lower voltage at the end of the feeder. This is caused by power flowing from the substation to the distribution loads through an impedance with a resulting voltage drop. Substation transformer tap changers keep line voltages within acceptable limits. The major challenge is keeping the steady state low voltage on the ends of the feeder within acceptable limits.

With the advent of QFs, great emphasis was placed on interconnecting these projects at the least cost. The result has been many projects connected to distribution feeders. Now in addition to low voltage concerns, steady state high voltage problems can result from reversed power flow when the distribution feeder load is low and the dispersed generation is high. These same substation transformer tap changers, line voltage regulators, and switched capacitor banks must now be located and programmed for this condition also. Often the placement and control settings required to avoid aggravating the high voltage situation reduce the effectiveness of the equipment to compensate for low voltage conditions. Keep in mind that the transition from power flow into the substation to power flow out of the substation can occur at any time. QFs are not under any obligation to generate into our system. Their operating directive is simply to maximize profit. In addition to generating only when they choose, most projects trip off line frequently due to system disturbances or generating equipment malfunctions. The result is our system experiences a wide range of load flow patterns. So far we have been able to avoid any voltage excursion outside of acceptable limits, but the potential for trouble is there and requires continued monitoring and planning. An example of this situation is the Little Wood River Reservoir 2,400 kW project which is connected to our Picabo distribution feeder. The feeder experiences wide fluctuations in power flows. Steady state voltages, while remaining within acceptable limits, vary from one extreme to the other. Over $500,000 in reconstruction and conversion to a higher operating voltage on the feeder was required to keep the voltage fluctuations within acceptable limits.

Transient voltage fluctuation caused by QFs equipment is also an operating problem. Elk Creek is a QFs in our Western Division on a distribution feeder serving the town of Riggins, which is 31 miles from a substation. The Elk Creek generation is located about 15 miles from the town of Riggins. Since the project first began testing, transient voltage disturbances have been experienced in the Riggins area. A particularly long and harmonic rich transformer energizing inrush current is producing a long duration voltage disturbance which has caused repeated misoperation of another QF on the same feeder. That demonstrates the potential for transient disturbances caused by locating large pieces of electrical equipment on distribution feeders designed to serve residential and commercial loads.

Environmental Considerations

Because of the territory that Idaho Power Company serves, the majority of the small power production has been constructed on creeks, streams, and rivers that are tributaries to the Snake and Salmon Rivers. It may be said that the framers of PURPA were primarily thinking of hydroelectric plants that would be installed at existing dams or structures on various rivers or tributaries. However, in our service area, that is not the case. Most of the small power hydro facilities are being constructed upon the river tributaries, many of which have never had structures or impoundments before. Consequently, they are having a serious impact on the local fisheries as well as creating a potential problem for the anadromous fisheries in our service area. As an example, the attached Exhibit II, Cogeneration and Small Power Production Status Report dated May 19, 1986, shows many of the future hydro projects would be on the tributaries of many of our streams and rivers.

The major concern of Idaho Power Company are those facilities proposed on the Salmon River and its tributaries. The Company has anadromous fish hatcheries and rearing facilities on the Salmon River and its tributaries. Our commitment to fish and wildlife and recreation in our service area is well-founded and documented. We have spent nearly $30,000,000 developing and maintaining fish hatcheries, enhancing wildlife habitats, and providing recreation facilities. Although FERC has instituted a cumulative impact study on the Salmon River and its tributaries, the Company is deeply concerned in other areas as well. As an example, attached as Exhibit III, supplied by the Idaho Department of Fish and Game, there have been major structural failures at many small hydro projects that are listed in the Exhibit. You will note that many of these facilities are on rivers, creeks, or tributaries to rivers or creeks that heretofore had no installations or impoundments.

Just and Reasonable

Section 210 of PURPA--namely Cogeneration and Small Power Production--states that the rates that a utility must pay a QF shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and shall not discriminate against qualifying generators or qualifying small power producers. An example of that fairness is demonstrated by a cogenerator on our system called the Tamarack Energy Partnership. This facility was built to utilize wood and waste wood from a sawmill. A portion of its energy was used to operate its sawmill and the excess energy that is generated was sold to Idaho Power Company. The FERC regulation, issued April 3, 1980, addresses simultaneous purchase and sales. It states that the proposed rule requires an electric utility to purchase energy from the cogenerator (Tamarack Energy) at its avoided cost--the total output of the facility--and in return the utility is to sell energy simultaneously to the facility at its retail rate. Now if the object of PURPA was to make our nation energy independent, it would seem to me that a cogenerator or small power producer would generate electricity to supply its own requirements first, and then sell the surplus energy to a utility at an avoided cost. However, that is not the way the rule was written. Consequently, this facility now is selling all its energy for 7.3 cents and simultaneously buying energy for its own requirements at 3.7 cents per kilowatt hour. A difference of 3.6 cents per kilowatt hour is billed to the rest of the ratepayers of the utility. It would appear that other customers are paying them $110,000 a year to use their own energy. Is this just and reasonable? In an area of surplus, such as the Northwest and Idaho in particular, where is the just and reasonableness of this type of energy sales or purchases?

Another example of your simultaneous purchase and sales is the Reynolds Irrigation District which just went into operation this month. The Reynolds Irrigation District had a siphon that ran from the top of a hill, across the Snake River and to their agricultural lands where they furnished water for their irrigation district. The pipe was becoming perforated due to age. Idaho Power offered to help pay to reinforce or replace the pipe across the river, but the Irrigation District refused to accept our contribution. Instead, the District installed a small power facility on the pipe at the bottom of the hill and began generating energy we are forced to buy at 6.97 cents per kilowatt hour. Then the District went across the river and installed a pumping plant for which it is entitled to an irrigation rate of just over 2 cents a kilowatt hour. And you call that just and reasonable?

The final example is the Afton Generating Company limited partnership in the state of Wyoming. It is a cogeneration plant that burns waste wood. It is not even in the state of Idaho, let alone in the Idaho Power Company service area. This company's Prospectus says the project is expected to yield about a 20% cash return to the investor each year for the first seven years at which time the debt will be repaid. Their investors' cash return is expected to increase to about 50% per year for up to 28 more years. In addition to the very strong cash flow, the investors will benefit from investment tax credits, energy tax credits, and a five-year depreciation schedule. Collectively, these tax benefits will recover about 70% of the investors' investment the first year and shelter all his cash flows through the fifth year. It would appear to me that a nation that has a two trillion dollar deficit should discontinue handing out investment tax credits, energy tax credits, and five-year depreciation schedules to generating facilities whose energy is not needed. Idaho Power has been forced to purchase this energy at an average price of 11.5 cents a kilowatt hour. At the same time, our company is selling energy (kilowatt hours) to our residential customers at 4 cents a kilowatt hour, our irrigation customers for 2.5 cents a kilowatt hour, and our large industrials in the neighborhood of 2 to 2.5 cents a kilowatt hour.

I would suggest to the Committee that this is not just and reasonable to our customers.

Avoided Costs

Section 210d of PURPA states, for the purpose of this section, the term "incremental costs of alternative electric energy" means, with respect to electrical energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electrical energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source. The Federal Energy Regulatory Commission's regulations define avoided costs "as the cost to an electric utility of energy or capacity or both which, but for the purchase from a qualifying facility the electric utility would generate or construct itself or purchase from another source." It goes on to say that if by purchasing electric energy from a qualifying facility, a utility can reduce its energy costs or can avoid purchasing energy from another utility, the rate for the purchase from a QF is to be based on those energy costs which the utility can thereby avoid.

There are two problems associated with those definitions--the first of which is you are forced to purchase a QF's energy whether you need it or not. As incredible as it seems, need is not an issue. Second, you are required to sign long-term firm contracts for this energy that you do not need and at prices that are established by utilizing a coal-fired generating facility rather than energy that can be purchased from another source. The contracts that Idaho Power Company has been forced to sign for energy it does not need just from those generating facilities operating today will cost our ratepayers $1,171,891,332 over the life of the contracts.

It is possible to purchase this amount of energy for a period of up to ten years from other generating entities for far less than we are paying for cogeneration today. The Idaho Public Utilities Commission has required Idaho Power Company to pay cogenerators and small power producers rates that are "levelized". In short, this means that the small power producer is paid an amount which exceeds the value of his power for about the first twenty-five years of a thirty-five year contract. During the balance of the thirty-five year contract, the small power producer, if he chooses to remain in business, is paid less than the projected value of the power. At the end of the thirty-five year period, if all things have gone in accordance with the assumptions made at the outset, the overpayment drops to zero at the end of the thirty-five year contract.

The reason that I have said if the small power producer is still in business is because there are a number of the small hydro producers who have utilized pumps that are used for irrigation projects, setting them on two by sixes, and running them backwards to generate power. The life of those projects are very questionable. There is the possibility that the small power producer, after he derives all of his tax benefits and tax shelters and made reasonable amounts of revenue, has no desire or obligation to continue to operate these projects and consequently, they could go out of business or sell the project to someone who does not choose to keep them up. As a consequence, their dependability is questionable and so potentially is their generation.

In conclusion, we would be remiss if we did not propose or suggest to the Committee and Congress that they reevaluate PURPA and its rules and regulations as promulgated by the Federal Energy Regulatory Commission. One of the possibilities would be to repeal portions of PURPA relative to small power and cogeneration as they may no longer be of value. Two, remove that portion of the Act which requires the forced purchase of energy by utilities, where the energy is not needed, at extremely high rates. Three, make need a requirement before FERC or any other agency can issue a license or a permit for a small hydro project or before a developer of a cogeneration facility can qualify for a power sales contract. Four, place a cap on avoided costs. The amount that a utility would be required to pay a cogenerator would not exceed its average system costs. Five, clarify the option of a utility to obtain additional energy supplies so that it would have the option to (1) construct its own facilities, or (2) purchase energy from cogenerators and small power producers, or (3) purchase energy from other sources. The ultimate purpose behind that would be that your consumers who are actually paying the bills would derive the most reasonable cost energy and more than likely the most reliable energy, or (6) allow the revisiting of contracts by defining how the term 'legally enforceable obligation' is used in FERC regulations. Today utilities in some areas are obligated to sign firm thirty-five year contracts which have escalators that increase the costs dramatically over the period of the contract. This is neither fair, just, nor reasonable to the customers or to the utilities. If you really want to be fair, just, and reasonable to your constituents, you will repeal the investment tax credits, energy tax credits, and the five-year depreciation schedules for cogeneration and small power producers. This list is not necessarily in priority of importance, but is a suggestion to the Committee for their consideration.

Thank you for this opportunity to discuss this issue with you.

Logan Lanham
Idaho Power Company
Boise, Idaho

EXHIBIT I

Idaho Power

SYSTEM OPERATING REPORT

TUESDAY

(FIGURES SUBJECT TO REVISION)

DATE May 20, 1986 AST

SYSTEM PEAK HOUR 2 PM to 3 PM	MW AT SYSTEM PEAK	MW AVE	SYSTEM WEATHER		
AMERICAN FALLS	108	108.7	BOISE		
TFPR/SFPR/USPR	53	54.0		TODAY	LT YR
LOWER SALMON	63	63.2	MAX	80	73
BLISS	69	68.6	MIN	54	47
SPRING PLANTS	22	22.2	PRECIP	0.04	0.00
C.J. STRIKE	86	85.8	BURLEY		
SWAN FALLS	7	7.8		TODAY	LT YR
CASCADE	4	4.9	MAX	80	69
			MIN	47	41
PLANT USE	-2	-1.3	PRECIP	0.03	0.00
TOT. UPPR SNAKE	410	413.9	POCATELLO		
				TODAY	LT YR
			MAX	82	73
			MIN	50	42
BROWNLEE	612	571.9	PRECIP	0.00	0.00
OXBOW	200	198.6	LAST YEAR		
HELLS CANYON	290	287.6	PEAK	AVG	
TOTAL HYDRO	1512	1472.0	1502	1171.9	
BOARDMAN	0	-0.2	-1	-0.3	
BRIDGER	147	147.2	319	391.5	
VALMY	0	0.0	2	35.6	
WOOD RIVER & SALMON	0	0.0	0	0.0	
MISC. GEN.	0	0.0	0	0.0	
COGENERATION	49	47.8	17	14.6	
TOT. GENERATION	1708	1666.8	1839	1613.3	
SYSTEM LOAD	1687	1487.2	1606	1415.4	
LOAD FACTOR		88.2%		88.1%	
FMC	222	211.1	224	207.4	
AEC	6	4.0	26	25.1	
MONSANTO	0	0.0	55	26.1	
LOAD-CHEM & AEC	1459	1272.1	1301	1156.8	
% LAST YEAR	12.1	10.0	1.6	0.7	
SURPLUS HYDRO		88.1		0.0	

STORAGE	THIS YR	LAST YR	DIFFERENCE	CAPACITY
JACKSON LK	44440	189850	-145410	824,360
PALISADES	429900	1191145	-761245	1,201,000
ISLAND PK	133336	134798	-1462	127,265
AMRCN FALLS	1626954	1666202	-39248	1,672,590
TOTAL (U SN)	2234630	3181995	-947365	3,825,215
ANDERSON R.	392041	417384	-25343	423,200
ARROWROCK	168031	226855	-58824	286,600
LUCKY PEAK	162275	238240	-75965	278,200
LK. LOWELL	157646	130442	27204	169,000
TOT. (BOISE)	879993	1012921	-132928	1,157,000
CASCADE	463333	559414	-96081	653,200
DEADWOOD	155268	161494	-6226	161,900
TOTAL (PAY)	618601	720908	-102307	815,100
OWYHEE	715620	701872	13748	715,000
BROWNLEE	1134887	1295004	-160117	1,420,082*
TOT. (ABOVE)	5583731	6912700	-1328969	7,739,015

	ELEV	AVE FLOW	DRAFT	TOT USE
AMRCN FALLS	4353.71	27786	SF	AF
PRIMARY				
PALISADES	5558.14	17970		AVE FLOW
			MILNER	18113
			BOISE R.	3760
			PAYETTE R.	5627
BROWNLEE	2054.92		WEISER	40133
BN INFLOW		40830	SALMON R.	28845
BN ELEV DIF	0.64		MAXIMUM	MINIMUM
HELLS CANYON	1687.41	37014	39820	33670

AFPR D.O. MIN= 10.30

AFPR TOTAL LOST POWER= 0

TRANSACTIONS WITH OTHER UTILITIES (NET)	ACTUAL INTERCHANGE		SCHEDULED INTERCHANGE	
	PEAK	AVERAGE	PEAK	AVERAGE
UTAH POWER & LIGHT	268	38.4	569	372.4
MONTANA POWER & LIGHT			8	9.0
WASHINGTON WATER POWER	-139	-34.5	-174	-175.0
PACIFIC POWER & LIGHT	-336	-80.3	-322	-20.0
SIERRA PACIFIC	245	220.4	246	242.0
BONNEVILLE POWER ADMINISTRATION	-63	-11.6	-349	-295.9
USBR (BPA)	27	26.1	27	26.1
TOTAL SCHEDULED INTERCHANGE			5	158.6
TOTAL METERED INTERCHANGE	2	158.6		
INTERCHANGE FOR GENERATION TRANSFER	6	6.0		
TOTAL ACTUAL INTERCHANGE	8	164.6		
SYSTEM INADVERTENT	-3	0.0		
CIRCULATING FLOW AT WEST INTERCONNECTION	429	467.5		

WHEELING REFERENCE ONLY	EAST (PEAK)	WEST	EAST (AVERAGE)	WEST
UTAH POWER & LIGHT	501	0	256.0	0.0
MONTANA POWER & LIGHT	0	0	0.0	0.0
WASHINGTON WATER POWER	0	0	0.0	0.0
PACIFIC POWER & LIGHT	0	23	0.0	86.3
SIERRA PACIFIC	55	38	25.9	38.1
BONNEVILLE POWER ADMINISTRATION	24	0	24.0	0.0

*INCLUDES 444,744 AF DEAD STORAGE

CAD-A-139 SYSTEM

EXHIBIT I

A5'

Idaho Power

SYSTEM OPERATING REPORT

(FIGURES SUBJECT TO REVISION)

WEDNESDAY
DATE May 21, 1986

SYSTEM PEAK HOUR 10 - 11 A.M.	MW AT SYSTEM PEAK	MW AVE	LAST YEAR PEAK	LAST YEAR AVG
AMERICAN FALLS	108	108.5		
TFPR/SFPR/USPR	55	54.5		
LOWER SALMON	64	65.3		
BLISS	72	70.5		
SPRING PLANTS	21	22.0		
C.J. STRIKE	86	85.9		
SWAN FALLS	8	7.8		
CASCADE	4	3.8		
PLANT USE	-2	-1.6		
TOT. UPPR SNAKE	416	416.7		
BROWNLEE	629	556.3		
OXBOW	201	200.4		
HELLS CANYON	293	292.6		
TOTAL HYDRO	1539	1466.0	1368	1135.0
BOARDMAN	-1	-0.3	0	-0.3
BRIDGER	143	147.4	518	516.5
VALMY	0	0.0	44	14.0
WOOD RIVER & SALMON	0	0.0	0	0.0
MISC. GEN	0	0.0	0	0.0
COGENERATION	32	34.5	10	10.6
TOT. GENERATION	1713	1647.6	1940	1675.8
SYSTEM LOAD	1687	1474.6	1704	1507.7
LOAD FACTOR		87.4%		88.5%
FMC	206	196.6	212	207.2
AEC	24	20.9	23	24.5
MONSANTO	0	0.0	54	23.3
LOAD-CHEM & AEC	1457	1257.1	1415	1252.7
% LAST YEAR	3.0	0.4	8.7	8.7
SURPLUS HYDRO		0.0		0.0

SYSTEM WEATHER

BOISE	TODAY	LT YR
MAX	56	82
MIN	48	52
PRECIP	0.05	0.00

BURLEY	TODAY	LT YR
MAX	64	78
MIN	42	45
PRECIP		0.00

POCATELLO	TODAY	LT YR
MAX	62	80
MIN	50	45
PRECIP	0.53	0.00

STORAGE	THIS YR	LAST YR	DIFFERENCE	CAPACITY
JACKSON LK	47610	200350	-152740	284,450
PALISADES	425970	1192273	-766303	1,201,000
ISLAND PK	133497	135443	-1946	127,265
AMRCN FALLS	1619513	1659232	-39719	1,672,590
TOTAL (U SN)	2226590	3187298	-960708	3,285,305
ANDERSON R.	393300	420645	-27345	423,200
ARROWROCK	170277	225999	-55722	286,600
LUCKY PEAK	165430	239627	-74197	278,200
LK. LOWELL	157181	130441	26740	169,000
TOT. (BOISE)	886188	1016712	-130524	1,157,000
CASCADE	465320	564592	-99272	653,200
DEADWOOD	156350	163110	-6760	161,900
TOTAL (PAY)	621670	727702	-106032	815,100
OWYHEE	715883	701900	13983	715,000
BROWNLEE	1155595	1310801	-155206	1,420,062
TOT. (ABOVE)	5605926	6944413	-1338487	7,392,467

	ELEV	AVE FLOW	DRAFT	TOT USE
AMRCN FALLS	4353.58	26678	SF	AF
PRIMARY				
PALISADES	5557.72	19520		AVE FLOW
			MILNER	16269
			BOISE R.	3200
			PAYETTE R.	7004
BROWNLEE	2056.71		WEISER	40825
BN INFLOW		42652	SALMON R.	38310
BN ELEV DIF	1.79		MAXIMUM	MINIMUM
HELLS CANYON	1687.12	32585	33670	30780

AFPR D.O. MIN= 10.50
AFPR TOTAL LOST POWER= 0

TRANSACTIONS WITH OTHER UTILITIES (NET)	ACTUAL INTERCHANGE PEAK	ACTUAL INTERCHANGE AVERAGE	SCHEDULED INTERCHANGE PEAK	SCHEDULED INTERCHANGE AVERAGE
UTAH POWER & LIGHT	176	99.3	479	433.4
MONTANA POWER & LIGHT			10	9.0
WASHINGTON WATER POWER	-105	-32.7	-324	-278.0
PACIFIC POWER & LIGHT	-216	-107.2	-72	-18.6
SIERRA PACIFIC	197	198.0	227	231.1
BONNEVILLE POWER ADMINISTRATION	-58	-20.5	-329	-240.8
USBR (BPA)	42	37.0	42	37.0
TOTAL SCHEDULED INTERCHANGE			33	173.1
TOTAL METERED INTERCHANGE	36	174.0		
INTERCHANGE FOR GENERATION TRANSFER	0	1.1		
TOTAL ACTUAL INTERCHANGE	36	175.1		
SYSTEM INADVERTENT	3	0.9		
CIRCULATING FLOW AT WEST INTERCONNECTION	482	526.5		

WHEELING REFERENCE ONLY	EAST (PEAK)	WEST (PEAK)	EAST (AVERAGE)	WEST (AVERAGE)
UTAH POWER & LIGHT	457	0	355.6	0.0
MONTANA POWER & LIGHT	0	0	0.0	0.0
WASHINGTON WATER POWER	0	0	0.0	0.0
PACIFIC POWER & LIGHT	0	9	0.0	27.5
SIERRA PACIFIC	75	38	17.7	38.1
BONNEVILLE POWER ADMINISTRATION	25	0	25.0	0.0

PAGE 1

EXHIBIT II

COGENERATION AND SMALL POWER PRODUCTION STATUS REPORT
DATE: 05/09/86

PROJECT NUMBER	PROJECT NAME LOCATION	KW	RECEIVED DIVISION COMMENTS	DEPARTMENTS NOTIFIED	PRELIM MEETING	CUSTOMER MEETING	ENGINEER APPROVAL	CONTRACT SIGNED	1ST ENERGY DATE(PROP)	DATE 1ST GENERATED
PRELIM 3	COLEMAN ELECTRIC LEADORE, IDAHO	400	06/01/82 INACTIVE	HYDRO PROJECT						
PRELIM 4	YANKE ENERGY ABERDEEN, IDAHO	7,500	11/22/82 INACTIVE	11/23/82 COGENERATOR						
PRELIM 6	MILLER, ROBERT L. JEROME, IDAHO	6	03/10/82 INACTIVE	WINDMILL						
PRELIM 9	CLOSE, JAMES POCATELLO, IDAHO	10	12/03/82 INACTIVE	12/16/82 WIND GENERATOR						
PRELIM13	WATTS, PHILIP S. BLACKFOOT, IDAHO	20	12/03/82 INACTIVE	12/16/82 WIND GENERATOR						
PRELIM14	SJELIN, PAUL H. ROCKLAND, IDAHO	10	12/03/82 INACTIVE	12/16/82 WIND GENERATOR						
PRELIM15	WEBB, ED PINGREE, IDAHO	10	12/03/82 INACTIVE	12/16/82 WIND GENERATOR						
PRELIM16	ISAAK, ESTER AMERICAN FALLS, IDA	20	12/03/82 INACTIVE	12/16/82 WIND GENERATOR						
PRELIM21	AUGER FALLS N OF TWIN FALLS	43,600	01/18/83 INACTIVE	NEAR ROCK CREEK						
PRELIM22	STAR FALLS TWIN FALLS	30,000	07/28/83 INACTIVE	5MI DNSTRM FROM MILNER DAM						
11131114	VICTORY SOLAR 6809 BARON AV. BOISE	0	08/31/84	09/05/84 1 PHASE 120V PHOTOVOLTAIC			09/12/84			01/27/85
11414102	RAPID RIVER RANCH SE QTR SEC1 T23N R1W	187	03/30/84 INACTIVE	04/04/84 NOT IN SALMON RIVER CORP.						
11415009	DEVENY, WILLIS RIGGINS, IDAHO	110	07/14/81	01/05/82 SHINGLE CREEK	01/06/82	02/15/82	05/15/82	08/25/82		07/15/83
11415033	LITTLE SALMON R. EST S. OF RIGGINS	368	01/04/83 INACTIVE	01/17/83 FALL CREEK						
11415036	CROSS-O-RANCH S. OF RIGGINS	198	01/04/83 INACTIVE	01/17/83 SHEEP CREEK						
11415041	EBERLE, DONALD S.W. OF RIGGINS	349	01/04/83 INACTIVE	01/17/83 SQUAW CREEK						

COGENERATION AND SMALL POWER PRODUCTION STATUS REPORT
DATE: 05/09/86

PROJECT NUMBER	PROJECT NAME LOCATION	KW	RECEIVED DIVISION COMMENTS	DEPARTMENTS NOTIFIED	PRELIM MEETING	CUSTOMER MEETING	ENGINEER APPROVAL	CONTRACT SIGNED	1ST ENERGY DATE(PROP)	DATE 1ST GENERATED
11415042	GILL, DEWARD W. OF RIGGINS	393	01/04/83 INACTIVE	01/17/83 UPPER SQUAW CREEK						
11415047	GALLI, CLIFF N. OF RIGGINS	276	01/04/83 INACTIVE	01/17/83 S. FK. RACE CREEK						
11415048	GILL, D&W N.W. OF RIGGINS	229	01/04/83 INACTIVE	01/17/83 GRAVE CREEK						
11415051	CARLSON, GUY M E. OF RIGGINS	406	01/04/83 INACTIVE	01/17/83 ALLISON CREEK						
11515037	CROSS-O-RANCH S. OF RIGGINS	656	01/04/83 INACTIVE	01/17/83 RATTLESNAKE CREEK						
11515049	BICANDI, THOMAS L. N.W. OF RIGGINS	591	01/04/83 INACTIVE	01/17/83 W. FK. RACE CREEK						
11615034	BROWN INDUSTRIES S. OF RIGGINS	791	01/04/83 INACTIVE	01/17/83 HARD CREEK						
11615035	BROWN INDUSTRIES S. OF RIGGINS	1,369	01/04/83 INACTIVE	01/17/83 HAZARD CREEK						
11615044	YATES / HUBBARD S. OF RIGGINS	902	01/04/83 INACTIVE	01/17/83 LOWER HAT CREEK						
11615045	YATES, RALPH S. OF RIGGINS	911	01/04/83 INACTIVE	01/17/83 UPPER HAT CREEK						
11615046	WICKS, DELBERT S. OF RIGGINS	1,147	01/04/83 INACTIVE	01/17/83 LITTLE SALMON #6						
11615052	CARLSON, GUY M. E. OF RIGGINS	1,121	01/04/83 INACTIVE	01/17/83 PARTRIDGE CREEK						
11615053	CARLSON, GUY M. E. OF RIGGINS	2,204	01/04/83 INACTIVE	01/17/83 ELKHORN CREEK						
11615054	JOHNSON/WALTERS/LARS E. OF RIGGINS	889	01/04/83 INACTIVE	01/17/83 LAKE CREEK						
11615077	ELK CREEK 14M N OF NEW MEADOWS	2,000	05/19/83	06/21/83 ELK CREEK	07/14/83	10/13/83	06/21/84	08/31/84		04/03/86
11615097	GOOSE CREEK HYDRO 7 MI.NW OF MCCALL	3,856	02/27/84 INACTIVE	03/01/84	05/23/84		08/03/84			

COGENERATION AND SMALL POWER PRODUCTION STATUS REPORT

DATE: 05/09/86

PROJECT NUMBER	PROJECT NAME LOCATION	KW	RECEIVED DIVISION COMMENTS	DEPARTMENTS NOTIFIED	PRELIM MEETING	CUSTOMER MEETING	ENGINEER APPROVAL	CONTRACT SIGNED	1ST ENERGY DATE(PROP)	DATE 1ST GENERATED
11615115	MESA 2 SE OF COUNCIL IDAHO	4,900	09/11/84 INACTIVE	09/14/84	09/27/84	01/17/85	07/25/85			
11616038	CROSS-O-RANCH S. OF RIGGINS	3,098	01/04/83 INACTIVE	01/17/83 LITTLE SALMON #2						
11616039	CROSS-O-RANCH S. OF RIGGINS	2,498	01/04/83 INACTIVE	01/17/83 LITTLE SALMON #3						
11616040	CROSS-O-RANCH S. OF RIGGINS	2,778	01/04/83 INACTIVE	01/17/83 LITTLE SALMON #5						
11616043	YATES / HUBBARD S. OF RIGGINS	3,295	01/04/83 INACTIVE	01/17/83 LITTLE SALMON #4						
11616050	JUNGERT CORPORATION E. OF RIGGINS	4,393	01/04/83 INACTIVE	01/17/83 FRENCH CREEK						
11646055	ROYSTONE HOT SPRINGS SWEET, ID	1,200	01/20/83 INACTIVE	02/07/83 GEOTHERMAL PROJECT		03/08/83				
11716069	BOISE CASCADE HORSESHOE BEND, IDA	9,900	03/02/83 INACTIVE	03/15/83	04/21/83	02/14/84	10/25/84			
11766002	EVERGREEN ENERGY TAMARACK, IDA	5,000	05/10/81	06/01/81 WOOD WASTE COGENERATION	06/04/81	06/08/81	06/28/83	09/16/81		05/16/83
11866066	BOISE CASCADE EMMET SAWMILL	14,000	03/25/83	04/22/83	01/03/84	12/13/83	10/04/85	01/12/84		05/30/85
12314086	FORSEA HYDRO PROJECT UPPER HELLS CANYON	100	08/36/83 INACTIVE	08/29/83						
12414073	ANDERSON HYDRO NEW BRIDGE, OREGON	350	03/28/83 INACTIVE	03/31/83 RANCHERS IRRIGATION DIST	06/09/83					
12514079	CURRY DITCH 5MI N HALFWAY OREGON	420	06/21/83 INACTIVE	07/29/83	09/01/83					
12614070	MITCHELL BUTTE POWER MALHEUR CO. ORE.	1,675	03/01/83	03/15/83 HOSEY AND ASSOCIATES	01/03/84	12/13/83		06/06/85	01/01/89	
12615116	CITY OF HALFWAY 8 MI. NE OF HALFWAY	151,192	08/21/84 INACTIVE	09/19/84 ON RD TO CORNOCOPIA MINE	09/27/84		02/28/85			
12616071	OWYHEE DAM POWER P. OWYHEE DAM SUB	5,000	03/17/83	03/31/83 OWYHEE IRRIGATION DIST	01/03/84	12/13/83	11/30/84	04/27/84		05/08/85

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12616072	TUNNEL #1 POWER P TUNNEL CANYON	4,800	03/17/83	03/31/83 OWYHEE IRRIGATION DIST	01/03/84	12/13/83		06/06/85	01/01/92	
12746076	VALE GEOTHERMAL VALE OREGON	10,400	07/04/84 INACTIVE	07/09/84 EASTERN OREGON ELECTRIC		08/14/8				
21415119	REYNOLDS IRRIGATION 14.5MI SO OF NAMPA	264	12/25/84	11/06/84 BY WALTERS FERRY BRIDGE		11/02/84	01/23/85	07/01/85		04/23/86
21454087	W BOISE WASTEWATER BOISE	58	08/25/83 INACTIVE	BIOMASS AT BOISE SEWER FAC						
21615078	BARBER DAM NW OF BOISE	4,140	05/30/83 INACTIVE	05/31/83	07/14/83	10/17/83	03/22/84			
21615108	MORA DROP 3MI SW OF KUNA	2,300	04/15/84 INACTIVE	05/09/84 ON MORA CANAL	05/09/84		08/10/84			
21615109	MAIN CANAL #6 2.5MI E OF KUNA	2,000	04/15/84 INACTIVE	05/09/84 MORA/MAIN CANAL JUNCTION	05/09/84		08/10/84			
21765095	TASCO SUGAR FACTORY N.SIDE BLVD &KARCHER	5,000	01/04/84 INACTIVE	01/09/94 5 TO 15 MW COAL BOILER	01/23/84	02/16/84				
31115016	BEAVER RANCH TWIN FALLS, IDAHO	27	08/20/84 INACTIVE	08/22/84 HANEY HEIDER AND MAYS			02/27/85			
31116019	POWERS, KENNETH TWIN FALLS, IDAHO	20	07/20/82 INACTIVE	08/02/82 20 KW 1 PHASE HYDRO PROJ	09/27/82		06/21/83			
31214058	BIRCH CREEK TROUT CO HAGERMAN	51	01/26/83	02/07/83 CLIFF JENSON	02/10/83		08/17/83	07/01/83		03/29/84
31214059	AQUA LIFE CO. JEROME	40	01/20/83 INACTIVE	02/07/83 WELL #1	05/27/83					
31315008	H.E.E.D. CO. INC TWIN FALLS, IDAHO	73	02/18/82	03/10/82 BIGGS/SLAUGHTERHOUSE CK	03/16/82		07/25/82			02/01/83
31315021	BOWLER, ALDRICH HAGERMAN, IDAHO	70	09/14/82	09/16/82 SNAKE RIVER POTTERY	09/27/82		11/23/83	07/11/84		11/19/84
31315022	WRIGHT, GARY BUHL, IDAHO	75	08/26/82 INACTIVE	08/31/82 KANAKA CREEK	09/27/82		02/16/83			
31315029	WHITE WATER RANCH CO HAGERMAN, IDAHO	160	09/14/82	09/16/82 SITE #1 & #2 COMBINED	09/27/82		02/16/83	05/16/84		07/11/85

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31315093	CITY OF HAILEY HAILEY	62	03/30/83	12/28/83 CITY WATER SYSTEM TURBINE	05/17/84	05/08/84	06/13/84	06/24/85		02/17/85
31316010	STEVENSON, LYNN BLISS, IDAHO	75	10/15/81	11/05/81 EXISTING HYDRO PLANT #1	01/15/82	11/03/83	11/23/83	01/12/84		03/23/84
31316011	STEVENSON, LYNN BLISS, IDAHO	65	10/15/81	11/05/81 EXISTING HYDRO PLANT #2	01/15/82	11/03/83	11/23/83	01/12/84		07/05/84
31316015	LEMOYNE, JOHN HAGERMAN, IDAHO	35	02/04/82	02/22/82 FISH HATCHERY	03/16/82	08/16/82	06/06/83	[illegible]/23/85		12/10/84
31414075	SNEDIGAR RANCH SILO CREEK - BUHL	540	05/06/83	05/13/83	06/22/83		01/27/84	02/24/84		12/31/84
31414110	FISHERIES DEV CO BILLINGSLEY CREEK	291	04/25/84	05/09/84 NE OF HAGERMAN	05/30/84		07/05/84			
31414111	WHITE(MUD CREEK) 2MI NW OF BUHL	205	05/07/84	05/09/84	05/30/84		07/16/84	07/23/85		01/10/86
31415017	NORTHSIDE CANAL Y-8 BLISS, IDAHO	85	08/01/82	08/17/82 IRRIGATION CANAL PROJECT	09/27/82		03/22/83	04/20/83		05/19/83
31415018	TWIN EAGLE HERZINGER BUHL, IDAHO	400	08/31/82 INACTIVE	09/16/82 SALMON FALLS CREEK	09/27/82	01/17/84	09/11/84			
31415023	CURRY CATTLE CO. FILER, IDAHO	222	09/03/82	09/16/82 ON IRRIGATION CANAL	09/27/82		01/24/83	02/07/83		06/04/83
31415024	HUDSON, DAN BUHL, IDAHO	293	08/01/82	08/16/82 DEEP CREEK	10/14/82		11/09/82		11/30/86	
31415025	WATER WATTS, INC. BUHL, IDAHO	179	08/28/82 INACTIVE	08/31/82 DEEP CREEK	10/14/82		11/09/82			
31415026	ABSHIRE, JIM BUHL, IDAHO	160	09/01/82 INACTIVE	09/16/82 DEEP CREEK	10/14/82		11/09/82			
31415027	TROUT CO. HAGERMAN, IDAHO	238	09/20/82	11/01/82 BILLINGSLEY CREEK	11/03/82		07/06/84	01/07/85	08/01/86	
31415065	BIG WOOD CANAL CO. GOODING	139	02/22/83	03/04/83 BLACK CANYON #3	05/04/83		07/18/83	03/02/84		04/16/84
31415000	1000 SPRINGS LEMMON HAGERMAN	275	05/28/81 INACTIVE	05/30/81 SEC31 T7S R14E						

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31415094	JIM KNIGHT 5.5MI E OF GOODING	340	12/23/83	12/28/83 ON BIGWOOD CANAL		01/10/84	04/20/84	06/10/85		09/14/84
31416001	COGENERATION, INC. SHOSHONE, IDA	382	05/04/81	07/30/81 ON IRRIGATION CANAL	07/30/81	08/13/81	08/17/81	10/13/81		06/21/82
31416007	10 SPRINGS (LEMMON) HAGERMAN	223	09/14/82 INACTIVE	09/16/82 NEAR 1000 SPRING	01/17/83		02/17/83			
31416013	KASTER, RICHARD BUHL, IDAHO	356	02/15/82	03/30/82 FISH HATCHERY	10/04/83	10/24/83	11/23/83	10/07/83		12/22/83
31416020	CANYON SPRINGS TWIN FALLS, IDAHO	130	09/21/82	10/04/82 CANYON SPNGS GOLF COURSE	10/14/82		10/26/82	04/12/84		09/20/84
31466006	WARD'S CHEESE RICHFIELD, IDA	200	07/06/81 INACTIVE	07/30/81 COGENERATION	11/17/81	12/09/81	12/10/81			
31515004	S & S PARTNERSHIP BUHL, IDAHO	520	09/02/81	09/10/81	09/22/81	09/29/81	10/28/81	10/30/81		02/20/82
31515009	RAVENSCROFT, VERNON TUTTLE, IDAHO	615	12/16/81	12/18/81 ON MALAD RIVER	01/08/82	01/21/82	05/11/83	09/02/82		11/15/83
31515060	AQUA LIFE CO. JEROME	506	01/20/83 INACTIVE	02/07/83 WELL #2	05/27/83					
31515061	AQUA LIFE CO JEROME	506	01/20/83 INACTIVE	02/07/83 WELL #3	05/27/83					
31515100	BRIGGS CREEK 7 MI. NORTH OF BUHL	600	04/02/84	04/04/84 ANOTHER KASTOR PROJECT		04/25/84	05/15/84	07/06/84		09/30/85
31515103	SAGEBRUSH POWERPLANT 7MI. E. OF GOODING	433	03/28/84	04/04/84 1.5 MI E OF JIM KNIGHT JOB	04/09/84		07/13/84	06/10/85		06/02/85
31515107	LITTLE WOOD(ARKOOSH) EAST OF GOODING	740	04/16/84	05/09/84 NW QTR SEC 28 T5S R16E	05/22/84		07/17/84	06/24/85	06/30/86	
31516014	CLEAR SPRINGS TROUT BUHL, IDAHO	520	06/05/82	06/20/82 FISH HATCHERY	08/24/82	09/03/82	06/22/83	12/16/82		11/02/83
31615003	COGENERATION, INC. ROCK CREEK(T.F.)	2,045	10/16/81	10/21/81	11/04/81		07/13/83	10/13/81		09/11/83
31615030	KOYLE, JOHN GOODING, IDAHO	1,250	10/18/82	10/20/82 MALAD RIVER	01/18/83	01/31/83	07/13/83	02/15/83		12/30/83

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31615031	KASEL & WITHERSPOON TWIN FALLS, IDAHO	900	10/19/82	10/22/82 IN TWIN FALLS	11/03/82		06/22/83	06/23/83		12/30/83
31615056	LATERAL #10 BUHL	1,600	12/20/82	01/31/83	09/01/83	11/08/83	02/28/84	06/08/84		05/03/85
31615057	CRYSTAL SPRINGS FILER	2,441	12/17/82	01/31/83	02/02/83	07/25/83	07/23/85	03/31/84		11/30/85
31615063	MAGIC SPRINGS BUHL	790	01/20/83 INACTIVE	02/10/83 VALLEY TROUT	05/04/83					
31615067	PIGEON COVE POWER CO FILER, IDAHO	1,890	09/20/82	10/04/82 ON CANAL	02/02/83	07/25/83	11/28/83	05/11/83		09/30/84
31615098	GEOBON 2 2 MI. E. OF SHOSHONE	927	02/27/84	03/01/84	04/03/84		09/05/84	03/01/85	08/01/86	
31615104	ROCK CREEK 2 4MI NW OF TWIN FALLS	1,900	04/11/84	05/09/84 TIES INTO ROCK CK SUBST	05/18/84	05/21/84	04/21/84			
31615105	LITTLEWOOD RES 9MI NW OF CAREY	2,400	04/09/84	05/09/84		06/25/84	07/25/84	07/27/84		02/23/85
31615106	DIETRICH DROP 5MI S OF DIETRICH	4,500	04/09/84	05/09/84 ON MILNER-GOODING CANAL		08/15/84	11/15/84			
31615113	BLIND CANYON HYDRO 5 MI N OF BUHL	1,548	05/29/84	05/31/84			09/10/84			
31615117	MARCOS RANCHES 5.5MI S 2MI W JEROME	1,200	09/16/84	09/20/84 ON NORTHSIDE CANAL		01/30/85	11/16/84	02/28/85		06/01/85
31615118	KIRTLEY-YORK HYDRO NW OF BELLLVUE IDAHO	965	10/01/84 INACTIVE	10/03/84 ON BIGWOOD CANAL			03/04/85			
31615120	ROYAL CATFISH HYDRO NE QTR S24 T9S R16E	2,800	11/30/84 INACTIVE	12/07/84 AQUA LIFE/WESTERN HYDRO						
31615121	FAULKNER RANCH NW OF BLISS	785	02/21/85 INACTIVE	02/25/85 NEAR NORTHSIDE PROJECT	03/27/85					
31615125	LOWLINE #2 4S, 1W KIMBERELY	7,900	03/05/86	03/07/86 4 MI WEST OF LOWLINE #1	03/07/86				11/01/86	
31616081	CEDAR DRAW NEAR TWIN FALLS	1,550	07/20/83	07/18/83	09/20/83	10/06/83	12/13/83	01/19/84		05/02/84

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31715099	LOWLINE CANAL 1.5MI. S. HANSEN ID.	7,970	03/14/84 ON LOWLINE CANAL	03/16/84	05/24/84	07/24/84	09/17/84	06/08/84		04/05/85
31715101	MALAD HIGH DROP SEC 6 T 6S R 13E	5,000	03/29/84 INACTIVE NEAR TUTTLE	04/04/84						
31715123	MAGIC RESORVOIR NORTH OF SHOSHONE	9,070	03/28/85 INACTIVE	04/10/85	04/26/85					
31715126	BYPASS 4E & 3S OF HAZELTON	9,900	04/28/86 ONE OF FOUR PROJECTS IN AREA TOTALING 35 MW						04/01/88	
31716082	BOULDER RAPIDS NE OF BUHL	9,000	07/08/83 INACTIVE RIVERSIDE POWER CO	07/18/83						
31716083	EMPIRE POWER PROJECT 4.5 MI N OF BUHL	6,400	07/08/83 INACTIVE	07/18/83						
33414085	BUSH RANCH WELLS, NEVADA	163	07/01/83 INACTIVE OFF IP SYSTEM							
41121080	IORG, JESS AMERICAN FALLS, ID.	10	05/24/82 INACTIVE WIND GENERATOR	06/15/82	07/01/82	08/06/82	08/12/83	08/12/83		
41121084	MAHM, WALLACE BLACKFOOT, IDA.	10	12/03/82 INACTIVE WIND GENERATOR	12/16/82						
41121088	PETERSON, GRANT BLACKFOOT, IDAHO	10	12/03/82 INACTIVE WIND GENERATOR	12/16/82						
41121089	THEUSON, JOHN BLACKFOOT, IDAHO	20	12/03/82 INACTIVE WIND GENERATOR	12/16/82						
41215028	FALL CREEK OSBORN AMERICAN FALLS, IDA	52	09/15/82 INACTIVE NEAR AMERICAN FALLS	10/04/82	10/14/82		02/16/83			
41415092	FALL CREEK - BENSON AMERICAN FALLS	150	11/28/83 INACTIVE FALL CREEK	12/05/83	01/03/84		03/19/84			
41415124	SUNSHINE POWER #2 11 MI SW OF SALMON	110	11/01/85 IN LAKE CREEK SUBDIVISION	11/08/85	12/19/85	01/19/86			08/01/86	
41455091	POCATELLO WASTEWATER NORTHWEST OF POC.	150	11/17/83 BIOMAS/POCATELLO SEWER FAC	12/06/83	01/03/84		03/13/84	06/28/85		12/05/85
41515122	SCHAFFNER HYDRO BTWN SALMON & TENDOY	525	02/26/85	03/07/85	03/29/85		10/31/85		06/30/86	

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PROJECT                               RECEIVED  DEPARTMENTS  PRELIM     CUSTOMER  ENGINEER  CONTRACT  1ST ENERGY  DATE 1ST
NUMBER   PROJECT NAME            KW   DIVISION  NOTIFIED     MEETING    MEETING   APPROVAL  SIGNED    DATE(PROP)  GENERATED
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         LOCATION                     COMMENTS
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41656064 BANNOCK CO  ENERGY    3,480  09/27/82    10/15/82   07/14/83   06/03/83
         POCATELLO, IDAHO             INACTIVE    MUNI WASTE COGEN FAC

41746096 RAFT RIVER GEOTHERM   5,000  01/26/84    01/31/84
         RAFT RIVER VALLEY            INACTIVE    OFF IP SYS (HYDROCO-MUNSON

41868112 SIMPLOT(POCATELLO)   12,000  05/16/84    05/17/84   07/18/84   07/31/84  06/07/85  01/08/86              01/13/86
         3 MI. W OF POCATELLO                     SULPHURIC ACID COGEN FAC

44767012 AFTON ENERGY INC      6,500  00/00/81                                              08/12/82              12/30/83
         AFTON, WYOMING                           OFF IP SYS WOOD BURNER
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EXHIBIT III

Known structural failures or major construction related impacts that have occurred at small hydropower projects in Idaho, March, 1986.

Project No.	Project Name	Stream	Structural Failure/Impact
472	Oneida	Bear River	- Penstock failure resulting in powerhouse washout
4052	Koyle Ranch	Big Wood River	- Bypass spillway failed and washed out
4055	Ravenscroft Ranch	Little Wood River	- Reservoir wing wall failed and washed out
4182	Shoshone	Little Wood River	- Flume failure and washout
4769	Mud Creek	Mud Creek	- Flume failure and washout
5089	Felt	Teton River	- Unauthorized road fill in Teton River; hillside and riparian habitat loss and blockage of spawning tributary due to sidecasting materials during road construction
5767	LQ-LS Drains	Drains	- Canyon wall failure during unauthorized road construction and placement of 10,000+ cubic yards of material in Snake River; hillside and riparian habitat loss due to sidecasting material during road construction
5892	Preston Hydro	Cub River	- Hillside slump into transmission line
6250	Lateral 10	Deep Creek	- Failure to meet bypass agreement
6443	Little Mac	Cedar Draw Creek	- Bank failure and washout around penstock intake
6450	Rock Creek	Rock Creek	- Flume failure and washout
8278	Crystal Springs	Cedar Draw Creek	- Unauthorized road fill in Cedar Draw Creek and associated wetlands; hillside and riparian habitat loss due to sidecasting material during road construction

R9FS080JT

Supplied by the Idaho Department of Fish & Game

EXHIBIT III

Project No.	Project Name	Stream	Violation
4052	Koyle Ranch	Big Wood River	- Failure to provide fish screens - Failure to provide fish bypass system
4055	Ravenscroft Ranch	Little Wood River	- Failure to provide minimum bypass flow - Failure to provide staff gauge
4769	Mud Creek	Mud Creek	- Failure to provide minimum bypass flow
5731	Coulee Creek	Coulee Creek	- Failure to provide minimum bypass flow - Failure to provide fish screens - Failure to provide staff gauge - Installed capacity exceeds that authorized - Constructed dam height exceeds exemption requirements
5767	LQ-LS Drains	Drains	- Failure to provide fish screens
6250	Lateral 10	Deep Creek	- Failure to provide minimum bypass flow
6443	Little Mac	Cedar Draw Creek	- Failure to provide fish bypass system
8278	Crystal Springs	Cedar Draw Creek	- Failure to provide erosion control or plan for same
6631	Mack's Creek	Mack's Creek	- Failure to provide fish passage - Inadequate screening - Improper intake design
4630	Briggs Creek	Briggs Creek	- Failure to provide fish screens - Failure to raptor-proof transmission lines

R9FS080JT

Supplied by the Idaho Department of Fish & Game

The CHAIRMAN. Mr. Hebert.

STATEMENT OF CALVIN J. HEBERT, SENIOR VICE PRESIDENT, OPERATIONS, GULF STATES UTILITIES CO.

Mr. HEBERT. Thank you, Mr. Chairman and members of the committee, for allowing me to file the testimony that I filed on behalf of my company, and for allowing me to make this 5-minute brief summary statement of that testimony.

My name is Calvin Hebert. My address is 350 Pine Street, Beaumont, TX, and I am senior vice president of operations for Gulf States Utilities Co., which is an electric public utility on whose behalf I am here.

The implementation of the cogeneration provisions of the Public Utility Regulatory Policies Act of 1978, or PURPA is producing a significant impact on the electric utility industry in the States of Louisiana and Texas, where my company provides retail electric service to commercial, residential, industrial, and wholesale customers.

Our experience permits us to make informed comment on the effect the development and operation of qualified cogeneration facilities are having upon the operations and reliability of our company where these facilities are installed.

To understand our perspective, you should know something about Gulf States Utilities Co. The company provides electric service to over 550,000 customers in southeast Texas and in Louisiana. Our service area includes the refining and petrochemical complexes situated on the Mississippi River, around Baton Rouge, LA, those near Lake Charles, LA, and those in the triangle bounded by southeast Texas cities of Port Arthur, Beaumont, and Orange.

In 1985, our industrial sales amounted to 40 percent of the company's total revenues, and about 51 percent of total kilowatthour sales. Petrochemical industry was the dominant force which influenced the growth in the company's load, as well as dictated the design and construction of new generation plant, baseload operations to achieve maximum reliability.

Because of the availability of low-cost natural gas, all generating plants operated by the company were gas-fired, and except for oil-burning capability which was developed during the period of gas shortages in the 1970's, the first alternate fuel burning unit on the system was a coal-fired unit, placed in service in 1982.

Gulf States was uniquely vulnerable to the economic pinch which was created by the constraints of the Fuel Use Act, on the one hand, and the inducements encouraging cogeneration included in PURPA on the other.

On the one hand, the Fuel Use Act dictated the elimination of the use of natural gas for boiler fuel after 1989, and prohibited the construction of new gas-powered generating units. While the first prohibition has been repealed, the second remains in effect but only for public utilities.

In order to ensure available capacity to meet load in the future, Gulf States was required to construct generating units using fuel sources other than gas and oil. We are now a major participant in two operating coal-fired units and we are the constructor and principal owner of the River Bend Nuclear Unit, which is in the final stages of testing and probably will be eligible to be placed in commercial operations within the next few weeks.

Construction programs to develop new capacity cost our company almost $3.5 billion and that amounts to about 60 percent of our total invested capital. The construction of coal and nuclear units as a replacement for natural gas was accomplished by many other electric utilities in the gulf-south region, with the result that there has been a release into the fuel market of annual volume of an estimated 1.5 trillion cubic feet of natural gas.

The availability of this volume of gas, together with other economic factors, contributed to a surplus of deliverable gas which has contributed to the sharp decline in the price of natural gas.

So, while we were building expensive plants in compliance with the Fuel Use Act to replace gas-fired generation so we would be in a position to provide reliable supply of electricity for our customers in the future, a large block of those customers, the industrials, driven by the inducements of PURPA, began developing cogeneration facilities to reduce, or in most instances, displace the service that we were attempting to preserve.

The inducement to cogenerate as provided by PURPA became more relevant as the prices of natural gas declined. Now, with spot gas being available at prices ranging from $1.45 to $1.75 per 1,000 cubic feet, and lower in some instances, the avoided cost formula under PURPA offers opportunities for windfall, or even obscenely profitable returns, for entrepreneurs building a PURPA machine, which is the common name of a facility that has been installed to burn natural gas, which only marginally, or oftentimes may not meet the efficiency standards of PURPA.

In our area, all of this keyed to the use of natural gas for boiler fuel. This is the same gas that utilities displaced in response to the Fuel Use Act and is the same resource that PURPA was designed to conserve.

Gulf States has lost about 400 megawatts of load to cogeneration and stands to lose another 1,050 megawatts if current conditions prevail.

This totals about 79 percent of our 1985 industrial load level. The company's 1985 peak load of 5,139 megawatts, was 8.2 percent below our historic peak of 5,604 megawatts, which was achieved back in 1980.

While the results of cogeneration are not the exclusive cause of the decline in load, it certainly is a major factor in the reduction. The impact of this loss of load due to cogeneration upon our remaining ratepayers and the shareholders of the company is exacerbated by the high construction costs of the required alternate generating capacity needed to comply with the Fuel Use Act and is contributing to a very high and uneconomic level of reserve.

The full cost of carrying the capacity released by the cogenerators, a portion of which is used as standby capacity for them, as mandated by PURPA, should certainly be borne by the cogenerators as a group, or this higher cost will inevitably be reflected in higher rates to our customers, or, alternatively, as an economic loss to the investors in the company's securities.

The cogeneration provisions of PURPA play only a part in creating the economic pressures which are impacting the electric system which is similarly situated in Gulf States. The impact of PURPA, however, is sufficiently great, in my opinion, to cause a reconsideration of legislative arrangement which permits facilities to utilize natural gas a fuel to qualify under the PURPA rules, especially when part of the intent of PURPA was to conserve this resource.

The availability and price of gas currently would seem in and of itself to provide adequate economic inducement for the construction of units that produce both steam and electricity without the added benefits of PURPA.

Thank you, again, for this opportunity, and I am advised that these proceedings may extend over several days, and that you will be receiving comments from numerous parties. We have tried to address in the summary and the full testimony, as well, those matters which we feel deserve the most attention in these proceedings. However, we would like to reserve the right to supplement the record later.

Thank you, very much.

[The prepared statement of Mr. Hebert follows:]

U.S. Senate Committee on Energy and Natural Resources

Oversight Hearing - PURPA Implementation

Testimony of CALVIN J. HEBERT - Gulf States Utilities Company

Washington, D.C.   June 3, 1986

Good morning. My name is Calvin Hebert. I am Senior Vice-President for Operations for Gulf States Utilities Company. My principal business address is 350 Pine Street, Beaumont, Texas. On behalf of Gulf States, please let me thank you, Senator McClure and the Energy and Natural Resources Committee, for allowing us to make these comments regarding the effects of current implementation policies related to the Public Utility Regulatory Policies Act of 1978. My comments will concern the effects of cogeneration on utility load, the effects on utility ratepayers resulting from inadequate compensation to utilities which must purchase cogenerated power, and certain serious problems which Gulf States perceives in the implementation of PURPA.

So that you may appreciate our perspective, let me tell you something about Gulf States Utilities. Gulf States was incorporated in 1925 under the laws of the State of Texas. It is primarily engaged in the business of generating, transmitting and distributing electricity throughout a 28,000 square mile area in Southeast Texas and South Central Louisiana. This service area extends approximately 350 miles from Baton Rouge, Louisiana to a point about 50 miles east of Austin, Texas and includes a total of about 556,000 customers. In 1985, sales of electricity to industrial customers (the primary participants in cogeneration projects) accounted for 40% of Gulf States' total revenues. Residential and commercial sales accounted for approximately 31% and 21% of the Company's sales, respectively. Gulf States' system peak load for 1985 was 5,139 MW. Total capacity available, including contract purchases of firm power, was 6,610 MW. This constitutes about a 22% capacity margin for the system. However, based on past forecasts predicting increasing load in the Gulf States service area and because of the Fuel Use Act constraints against the use of natural gas, historically our primary boiler fuel, the Company undertook the construction of a 940 MW nuclear power plant which will be placed in commercial operation this year. With the addition of this facility and the projected decrease in demand, the system capacity margin will approach a very high and uneconomic level.

Along the Gulf Coast, in Gulf States' service area, the petrochemical industry has been a dominant force. The needs of this industry for both steam and electricity have created a large and growing market for cogeneration projects. Gulf States estimates that about 1,431 MW of process industry now on its system has the potential steam/electric balance to displace load with cogeneration. This is compared to a current total industrial load on the system of 1,825 MW.

Obviously, it is the displacement of load by cogeneration which creates the most serious problems for a utility like Gulf States. The cost of cogenerated electricity is insignificant when compared to the real cost of cogeneration to the utility ratepayers and shareholders resulting from reduced load. If the amount of potential cogeneration cited above were realized, it would amount to a reduction of nearly $165 million per year in base revenues (excluding fuel costs) for the company - more than a 45% reduction in operating income. The burden of supporting the utility system built to meet the expected obligation to serve the electricity needs of all customers in our system would fall on those customers remaining - the residential and commercial customers. Potentially, their rates could increase by more than 15% as the result of cogeneration projects if the Company is not adequately compensated by the cogenerators.

Now, I would like to address other inadequacies we see in the implementation of PURPA and explain why I have stated that utilities have been inadequately compensated - and even penalized - under the Act. First, PURPA contains the provision that utilities must provide standby service at nondiscriminatory rates. This is fine, so far as it goes. The obligation to provide backup service to cogenerators would not be overly burdensome if utilities were adequately compensated for this service, but they are not! Our experience is that regulators are unwilling to set backup rates at levels which permit the utility to recover the true cost of providing this service. This not only provides an incentive for cogeneration but constitutes a direct subsidy of the cogenerator by the ratepayers remaining on the utility system.

The issue of compensation for backup services raises serious problems for Gulf States' ratepayers. As a regulated utility, Gulf States is obligated to serve all of its customers including its large industrial customers. when one of those industrial customers suddenly begins to cogenerate for his own use, and ceases taking baseload power from us, PURPA still requires us to serve that customer with backup power. As a result, we still have to maintain a large amount of generating capacity to serve this customer, even though we sell nothing but backup power to him. This is all fine, if we are adequately compensated for maintaining that capacity. If we are not sufficiently compensated, our ratepayers will have to bear the additional cost of maintaining this capacity, which is no longer being defrayed by the significant revenues we would have received if that customer had continued to purchase baseload power from us. In effect, cogeneration imposes a double financial burden on us: the cost incurred to maintain capacity which is used only to sell backup power, and the loss of revenues from a large baseload customer. If this financial burden is not adequately recovered through our backup power rates, then cogeneration will harm our residential ratepayers, by forcing them to pay for a larger portion of our system than they would otherwise have to support. We believe that was not the intent of PURPA, and that it undermines the goal of equity to ratepayers.

It is absolutely imperative that implementation of PURPA require that utilities be compensated for services required to be provided by the law. This should be done by determining the true cost of cogeneration to the utilities. This cost should include some allocation of reserve margin, a portion of administrative costs and an O&M component associated with the increased reserve margin. The allocation of reserve margin should be considered, based on loss of load probability determined without cogenerators. Cogenerators should pay the costs associated with the increased reserves. It should also include a component of cost allocated for units held in inventory, so long as the utility is obligated to serve cogeneration at the discretion of the cogenerators. To the extent that existing capacity is placed in inventory as a result of displaced load, cogenerators should at least pay the carrying charges associated with this capacity.

Another "real life" problem which Gulf States has experienced due to the way PURPA is being implemented, which increases costs to the ratepayer and the Company are the limited dispatch capabilities of Qualified Facilities, which may cause base load coal and nuclear capacity to be displaced. This is particularly true at night and at other times of light loading on the system. During such low load periods, the Company tries to utilize low cost coal and nuclear base load generation to meet its load. As the number of cogenerators increase, the coal and nuclear base load generators may have to be displaced. This results in higher operating costs caused by operating base load units in a load following manner, and in actually modifying some units to increase their load following capability. Based on the cogeneration projects that are planned, installed and under construction, we estimate that 575 MW of GSU generation equipment would require some modification to increase system load following capability. This could amount to 27 million dollars of costs which should certainly be recovered from the cogenerators.

We believe that these ratepayers and shareholder burdens are the result in large part of the implementation of PURPA - the actual implementation of the Act as much as the passage of the original legislation. In part it is also the result of the passage (and continuation) of the Fuel Use Act. When these two pieces of legislation were passed in 1978, Gulf States was essentially a 100% gas-fired utility. The Fuel Use Act required that utilities eliminate gas use by 1990 and prohibited the construction of new gas-fired generating units. While the prohibition against gas use after 1990 has been repealed, the prohibition against new gas-fired generating units is still in place. Faced initially with the absolute prohibitions against gas use, Gulf

States, like many other utilities, embarked on a plan to lessen its dependency on gas and diversify its fuel mix. This was done not only because it made good sense, but because it was required to meet the then expected future loads and the utility's obligation to provide service. Gulf States is now a participant in two coal-fired units and one nuclear powered unit. The Company is now less than 40% dependent on natural gas as a fuel source. Meeting these obligations has not been easy, nor has it been cheap. Gulf States has had to spend almost $3.4 billion to accomplish this goal, increasing its capitalization from about $1.6 billion to over $5 billion. When cogenerators leave the system, the remaining ratepayers suffer an increase in their unit cost for power under the current implementation of PURPA because implementation thus far has not recognized the true cost of cogeneration to the utility and its ratepayers and has failed to adequately compensate the utilities involved in cogeneration transactions.

One of the indirect effects of the passage of the Fuel Use Act has been the release of fluid fuels equivalent to about 1.6 trillion cubic feet of natural gas per year into the fuel market as a result of the construction of coal and nuclear power plants in the tri-state area of Louisiana, Texas and Mississippi. This released gas has contributed to the current low cost of gas in the Gulf States service area. In turn, this low cost fuel supply has contributed to an increased interest in cogeneration, particularly given that current implementation of PURPA has encouraged the construction of gas turbine cogenerating facilities which only marginally fit the requirements of cogeneration and which were in all likelihood not the facilities which Congress had in mind to encourage. Thus, by complying with the law and the then existing spirit of conservation of gas, the utilities have been forced to contribute to the development of the cogeneration market - without adequate compensation.

A recent study for Gas Research Institute by Energy and Environmental Analysis of Arlington, Virginia, shows that the Southwest Region of the U.S. is expected to have a 39% share of all cogeneration in the U.S. by the year 2000. The study also shows that 46% (1.729 trillion cubic feet) of the total natural gas fueled cogeneration capacity by the year 2000 will be located in the Southwest. It's quite probable that despite PURPA's intent to conserve it, the quantity of natural gas used for power generation in our region of the country will be equal to what it would have been absent PURPA because of flawed implementation. The difference is that this power will be produced by non-utility companies who have duplicated utility power production equipment at the expense of the utility ratepayer and shareholder.

The implementation of PURPA is largely a function of state regulation. Therefore it is important not only that you understand the problems created by policies developed in the implementation of the law, but that you effectively convey to the states your directives concerning the proper implementation of the law. We trust that our comments will help you in that regard.

Implementation of PURPA has failed in another crucial way. The zealous promotion of cogeneration has pressured regulators to be overly generous in awarding certificates to "Qualified Facilities". We believe that the original intent of the Act was to foster conservation and encourage the efficient generation of electricity through the use of alternative fuel sources. We have three cogenerators on our system which we do believe conduct operations consistent with the intent of PURPA. Two have taken process waste heat energy and used it to generate steam and electricity. The third utilizes rice hulls as fuel - certainly a "model" cogeneration project. However, instead of focusing support on these operations, the Act has been implemented to foster the increased use of natural gas in machines which barely meet the regulatory requirements of the Act and which by no means meet the original goals of the Act. The implications of this policy can clearly be demonstrated on the Gulf States system. Based on steam requirements from our industrial customers, there is a generation potential for electricity of 4,584 MW. This is 30% greater than our current base load of 3,400 MW. I think that you can see from what I have described earlier what the effect of this kind of cogeneration could be on the utility ratepayers and shareholders.

A final area in which implementation of PURPA has taken a decided turn from the direction plotted by the Congress, is in the area of forced transmission of power. Gulf States is an FERC jurisdictional utility and not subject to state imposed transmission requirements, but nonetheless in some instances, state regulators have superimposed on the requirements of PURPA transmission obligations which often fail to fully compensate the involved utilities, particularly where the utility's customer load is displaced. We believe that the provisions of PURPA related to transmission are adequate and should only be implemented in a manner consistent with the law.

Lest you begin to think that Gulf States is totally against cogeneration, let me tell you now about our interest in, and indeed our involvement in, the cogeneration field. Gulf States is, in fact, one of the original cogenerators in this country. We have operated, in Baton Rouge, for over 60 years a facility which provides process steam and electricity to refinery and chemical customers. Currently we are in the process of modernizing and expanding the capabilities of this facility. We are also actively negotiating with industrial customers to participate in cogeneration ventures utilizing existing facilities totaling in excess of 200 MW of electric generating capacity. In addition, we have plans to bring together ventures utilizing another 450 MW of capacity for cogeneration purposes. So, we are very interested in participating in cogeneration projects in an effort to preserve revenues which otherwise would be lost if our industrial customers go it alone. We believe our survival requires that we devise alternative ways to serve the needs of those who may otherwise turn to projects of their own, in order to lessen the burden on our other customers. Current ownership restrictions however, place an unfair burden on utility participants in these projects.

I would like to summarize the points which I have tried to make in my comments:

1. Utilities must be fully compensated. Standby rates must reflect the true cost burden thrust upon the utility and its other customers as a result of cogeneration transactions.
2. Utilities and cogenerators should be treated equally under PURPA and the Fuel Use Act.

We are optimistic that the upcoming legislative session will address the burdens placed on utilities by the implementation of PURPA. We look forward to working with the members of this committee in formulating an implementation policy which will permit an appropriate sharing of benefits among utilities, cogenerators and utility ratepayers.

Thank you, again, for this opportunity. I am advised that these proceedings may extend over several days and that comments may be received from numerous parties. We have tried to address those matters which we feel deserve the most attention in these proceedings. However, I would like to reserve the right to supplement the record by making responses to issues or positions which may materialize as these hearings progress. Your consideration will be appreciated.

The CHAIRMAN. Thank you, Mr. Hebert.
Mr. Peevey.

STATEMENT OF MICHAEL R. PEEVEY, EXECUTIVE VICE PRESIDENT, SOUTHERN CALIFORNIA EDISON CO.

Mr. PEEVEY. Thank you, Mr. Chairman and Senator Evans. It is a pleasure to be here today. My name is Michael Peevey and I am executive director of the Southern California Edison Co.

Before summarizing my remarks, I would like to compliment you for your leadership in commencing a new dialog on PURPA. Clearly a time has come for a serious congressional look at it.

First and foremost, we are proud of our efforts to implement the policy goals of PURPA. We have learned much in our experience with it.

Today, in part due to it, Edison has thoroughly incorporated conservation, cogeneration and renewable and alternative energy into our planning process. As a result, Edison derives electric power from nine different energy sources, more to our knowledge than any other utility in the world, and we are a better and more flexible company for it.

However, Edison is concerned that the congressional purpose in adopting PURPA has not been fully realized and, in fact, that a potential hardship for our customers may have been created.

If I could summarize in a couple of sentences, our testimony, I would say is as follows about California and the California experience: In the 7 years since the enactment of PURPA, a new utility with almost 16,000 megawatts of capacity is being developed, a utility which would rank about the 10 largest in the United States; a utility whose owners are not required to dedicate their property to public service, and have no obligation to serve; a utility that is guaranteed there will be market for 100 percent of its output; a utility whose owners operate without restriction on profit; and a utility that is a reliable source of power only when it is economically attractive for it to be so.

In short, the California experience with third-party generation has been too much, too soon, at too high a price.

With respect to Edison's experience in particular, there is no doubt that PURPA has achieved the goal of stimulating the development of cogeneration and small power production. Edison has executed contracts with the QF industry totaling approximately 7,000 megawatts of capacity through 1990.

Edison anticipates making payments of almost $1.5 billion to QF's in 1990. Additionally, California utilities have signed contracts with the QF industry, as I have already noted, totally nearly 16,000 megawatts of capacity by 1995. I might mention that this amount is substantially in excess of the 12,000 megawatts of QF capacity that FERC initially projected would develop in the entire Nation.

Clearly, the success of California in encouraging QF development has far exceeded everyone's expectations. However, the question one must ask is whether the abundance of electrical generation produced by the QF industry has achieved the other stated purposes of PURPA. We are concerned that as a result of the rapid growth in the QF industry, its ratepayers, our ratepayers, may incur adverse, economic and operational impacts.

Today, Edison has an excess amount of QF generation under contract at prices which do not provide equitable benefits to our customers. QF benefits to utility customers are limited, in part, because the contractual terms under which we have had to buy independently produced power are flawed.

Under the terms established by California regulatory authorities, Edison has, in many cases, paid more than it should for the electricity produced by QF's. In fact, we have been compelled to sign contracts for capacity and energy which are simply not needed to serve our customers.

Under the interim contract put in place by the California Public Utilities Commission, Edison ratepayers are exposed to energy payments to QF's which, if all QF's came on line, which is optimistic for that industry—unlikely, certainly—but if all QF's under contract came on line, we would be paying as much as $2.5 billion above our current forecasts of avoided costs in the early 1990's, and we would be paying $300–$400 million more than necessary for capacity not needed when it came on line.

Furthermore, in many cases, we have no contractual ability to dispatch the QF's output or to control its maintenance schedule. As you may be aware, an essential characteristic of the production of electricity, distinguished from many other products, is that supply must be kept in continuous balance with demand in order to maintain the quality of the product.

This requires a high degree of integration and coordination in planning and operating an electrical system. With QF industry providing prospectively larger amounts of power to Edison, it is essential to have QF's provide the operating characteristics necessary for effective supply-demand coordination.

Edison is therefore concerned that while PURPA does address reliability in the broad sense, there are currently no nationally established guidelines that address the reliability aspects of integrating QF's with the electric bulk power supply. Unbridled QF development can and will have potentially serious impact upon generation and transmission planning and operation, economic power pooling, and system integrity and reliability, all of which will ultimately lead to unnecessarily higher costs to our customers.

What is therefore needed to assure reliable, viable, economic and energy-efficient QF industry, while maintaining ratepayer equity, I believe that the first step would be to encourage the FERC to fully examine the current rules implementing PURPA and to determine whether the objectives of Congress are being met.

As a minimum, we recommend that FERC undertake a thorough examination in two major policy areas. The first is pricing. One, the avoided cost standard.

There is little doubt that FERC's avoided cost standard is an effective mechanism to QF development, in fact, so much so that our ratepayers derive little, if any, benefits.

In our opinion, this does not promote sound National energy policy. In light of the substantial QF development to date, in keeping with PURPA's goal of providing for ratepayer benefits, Edison recommends that investigation be undertaken of various shared savings approaches to QF pricing.

Second, capacity payment restrictions. Many States have exceeded PURPA's mandate and the FERC rules by requiring capacity payments to QF's in the absence of deferrable or avoidable utility resources. This strategy has resulted in ratepayers incurring higher costs than they would have without QF's and has wasted scarce economic resources.

Edison recommends that FERC's rules be amended to clearly direct State regulatory authorities to allow capacity payments for QF's only for, and in years in which deferrable or avoidable utility capacity can be specifically identified.

Three, regarding matching of QF operating characteristics to utility system needs. The emergence of a very large QF industry has led to problems for ratepayers which were unanticipated at the time of PURPA's enactment.

The absence of defined operating roles for QF's can jeopardize utility system reliability and/or require resource additions more costly than if QF operating characteristics were certain.

For example, if QF's elect to build principally nondispatchable resources, utilities may be forced to install more dispatchable and thus more costly resources to compensate. This result is both inequitable to ratepayers and economically inefficient.

We recommend the FERC regulations be modified to encourage States to develop mechanisms which require a reasonable degree of matching of operating characteristics between QF dispatching utility resources and dispatched resources themselves.

Another area regarding QF qualification criteria, we have a number of specific suggestions, also.

First, regarding restrictions in fossil fuel use. FERC rules regarding fuel use by QF's are designed to restrict the use of fossil fuels by small power producers to 25 percent of the total energy input. If PURPA's intent to reduce dependence on finite and volatile fuel supplies remains an important national policy priority, then Edison recommends reducing this limit with a 10 percent suggested level.

Two, regarding efficiency standards for cogenerators. FERC's nominal efficiency standards for cogenerators, 5 percent of total output in the form of useful thermal energy, have allowed for the development of, what has been referred to already, PURPA-machines, which are basically conventional generating stations with minimal cogeneration functions intended to circumvent utility regulation.

In keeping with PURPA's objectives of conserving oil and gas and making more efficient use of energy resources, Edison recommends that this criteria be substantially tightened.

Third, restrictions on utility ownership. The FERC rules impose a 50 percent limitation on utility ownership of a QF. This limitation clearly should be reexamined in light of today's changed circumstances. We see several good reasons for allowing greater utility participation, including the more efficient integration of QF resources and the more equitable treatment of the utility industry relative to other industries.

In recognition of this and to assist in producing appropriate market responses, we believe that utilities should be allowed to have unrestricted ownership rights.

Mr. Chairman, in closing, I again want to thank you for convening this hearing. I hope it is useful in shaping our Nation's energy policy in the years to come.

[The prepared statement of Mr. Peevey follows:]

PREPARED TESTIMONY

OF

MICHAEL R. PEEVEY

EXECUTIVE VICE PRESIDENT

SOUTHERN CALIFORNIA EDISON COMPANY

BEFORE THE

UNITED STATES SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

JUNE 3, 1986

SOUTHERN CALIFORNIA EDISON COMPANY

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PREPARED TESTIMONY OF MICHAEL R. PEEVEY
EXECUTIVE VICE PRESIDENT
SOUTHERN CALIFORNIA EDISON COMPANY
BEFORE THE
UNITED STATES SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
JUNE 3, 1986

EXECUTIVE SUMMARY

In California, in the seven years since the enactment of PURPA, a new utility with almost 16,000 megawatts of capacity is being developed; a utility which would rank among the ten largest in the U.S.; a utility whose owners are not required to dedicate their property to public service and have no obligation to serve; a utility that is guaranteed there will be a market for 100 percent of its output; a utility, many of whose owners are listed in the Fortune 500 and who operate without restriction on profit; a utility that is a reliable source of power only when it is economically attractive for it to be so.

The California experience with third-party generation has been too much, too soon, and at too high a price. The result is that our ratepayers face hundreds of millions of dollars in overpayments over the next several years and system reliability and operating problems. In this paper we address how we got to this point and make recommendations on how to avoid such problems in the future.

The stated objectives behind the passage of PURPA were:

1. Conservation of electric energy.
2. Efficient electric utility use of facilities and resources.

3. Equitable rates to utility customers.

4. Development of cogeneration and small power production.

These goals are worthwhile. However, the implementation of PURPA by FERC and the states has not achieved them in a balanced way. Instead, often the interests of ratepayers have been subordinated to the development of independent power producers. Favorable pricing provisions, apparently motivated by the viewpoint that the QF sector was an "infant industry" in need of subsidies, have exposed ratepayers to substantial overpayments to QFs. Furthermore, the rapid growth of QF development in some states presents serious problems for future system operation and reliability, and raises fundamental questions regarding a utility's traditional obligation to serve.

In view of the unexpectedly rapid growth in PURPA generation, we believe it is time for Congress to assess the record of PURPA implementation and take several positive steps to assure that the development of an independent power industry will benefit electricity ratepayers. In particular, our main concerns are the following:

o Reliability and Operability of the Electricity Supply System: The provision of reliable service to electricity customers involves complex integration and coordination of generation resources. As more and more of these resources become governed by arm's-length contracts rather than by direct utility management control, the reliability and operability of the electric system could be weakened. The manner in which QF development takes place must not be allowed to undermine utility system reliability. The ultimate loser would be the electricity customer.

- Service Obligation: Traditionally, utility customers have been protected by a utility's service franchise obligation to supply reliable power to all its customers. To help insure this obligation, laws governing utility property provide for it to be dedicated to the public service and place severe restrictions on its use and sale. The availability of PURPA generation, on the other hand, is governed by ordinary contract, not utility law. As PURPA generation begins providing a larger and larger portion of a utility's resources, it will be increasingly difficult and costly for utilities to meet their service obligation.

- Ratepayer Benefits: In implementing PURPA, the FERC was instructed by Congress to promulgate pricing rules which were just and reasonable to utility customers but not higher than a utility's avoided costs. In adopting its full-avoided-cost rule, the FERC decided that encouragement of cogeneration and small power production should take precedence over the provision of any direct benefits to utility ratepayers. Alternative negotiation and payment mechanisms (e.g., shared-savings arrangements) could have been devised to encourage the efficient development of independent power producers, while passing along significant direct monetary benefits to ratepayers. Considering the subsequent development of the PURPA generation industry and the participation in this industry by very large corporations, it no longer seems reasonable to treat it as an "infant industry". The FERC should modify its full-avoided-cost rule and adopt a pricing rule designed to provide some direct economic benefits to utility ratepayers.

- Payments in Excess of Avoided Costs: In many state jurisdictions, ratepayers have been subjected to overpayments to PURPA qualifying facilities for a variety of reasons, including: (1) use of inaccurate costing methods; (2) capacity payments made in the absence of need; (3) no timely updating of payment schedules; and (4) failure to allow for adjustments to avoided cost payments to reflect actual system conditions such as economy energy rejections during minimum loading of utility generation.

- Payment for Capacity in Absence of Need: Because of the utility's purchase obligation under PURPA, it is especially important to time avoided capacity cost payments accurately in order to encourage producers to begin delivering power when it is needed. The practice of paying for capacity in years before it is needed is a wasteful practice which places an unfair burden on ratepayers.

- Provision of Resource Dispatchability: In order to assure the operability and reliability of the electricity supply system, utilities must have greater flexibility to require certain contract provisions that assure the integrated and coordinated operation of all resources. The FERC rules provide for the adjustment of avoided cost payments to account for several beneficial operating characteristics of resources. However, price adjustments are not sufficient and the rules do not provide for contractual obligations governing the operating characteristics of independent producers even when such characteristics may be necessary to maintain the reliable operation of the system.

- Eligibility Rules for PURPA Qualification: In order to promote the conservation of oil and natural gas and the efficient use of energy, PURPA directed the FERC to develop certain fuel use and efficiency standards to govern the eligibility of generating facilities for PURPA benefits. Contrary to the original intent of the legislation, the subsequent FERC rules have actually encouraged the use of oil and natural gas by essentially allowing large amounts of supplementary conventional electric generation to be appended to non-conventional generation projects.

The preponderance of problems with PURPA have not come as a result of the statute itself, but as a result of the FERC's rulemaking and the wide latitude taken by states in its implementation. Therefore, Edison offers the following recommendations regarding PURPA's implementation:

- Payment of Full Avoided Costs: The FERC rules should be modified to encourage states to develop innovative pricing approaches designed to encourage QF development, while paying less than full avoided costs and thereby providing ratepayers with direct monetary benefits.

- Capacity Payment Restrictions: The FERC rules should be amended to clearly direct state regulators to allow capacity payments to QFs only for those years in which a deferrable or avoidable utility resource can be identified.

- Matching of QF Operating Characteristics to Utility Needs: The FERC rules should be modified to clarify and assure that QFs will provide utilities with needed performance characteristics to achieve system operability and reliability.

- Restrictions on Fossil Fuel Use: The FERC rules should reduce the allowed use of fossil fuels for supplemental boiler firing from 25 percent to 10 percent of total energy input to further promote independence from such fuels and increase fuel efficiency.

- Efficiency Standards for Cogenerators: The FERC rules governing efficiency should be tightened to discourage the development of "PURPA machines" designed to bootstrap conventional generating technologies to QF status.

- Restrictions on Utility Ownership: The FERC rules should be changed to allow for greater participation in QF development by utilities either directly or through their subsidiaries.

SOUTHERN CALIFORNIA EDISON COMPANY

Testimony of Michael R. Peevey

Executive Vice President

Before the

U.S. Senate Committee on Energy and Natural Resources

I

INTRODUCTION

The Public Utility Regulatory Policies Act ("PURPA") has been tremendously successful in stimulating the rapid growth of cogeneration and small power production. Nowhere is this clearer than in California, where utilities have signed contracts with independent power producers totaling almost 16,000 MW of capacity deliverable by 1990. A summary of California's renewable/alternative energy resources appears at the end this section. What is far from clear, however, is whether these purchases from independent producers will translate into long-term benefits for utility ratepayers or achieve the other stated objectives of the legislation. Furthermore, the unexpected size of the developing QF industry may lead to unanticipated operating and reliability problems.

An examination of the legislative record of PURPA suggests that a complex and diverse set of political concerns contributed to the formulation of Sections 201 and 210. These sections, consistent with the Carter Administration's National Energy Act, were designed to encourage the development of unconventional domestic generating resources (hereinafter referred to as "qualifying facilities" or "QFs") as a means of improving the overall efficiency of electric power production, reducing dependency on imported fuels, and diversifying the nation's energy resource base. An important motivation for this legislation was the perception that institutional barriers were inhibiting the development of a small but significant "fringe industry" of independent, nonutility power producers. These perceived institutional barriers included: (1) the reluctance of some utilities to enter into contracts with independent power producers; and (2) the reluctance of independent power producers to develop projects if subject to regulation as public utilities.

Under PURPA, broad discretion in promulgating rules was left to the Federal Energy Regulatory Commission ("FERC"), with still further flexibility in implementation passed on to the states. The stated purposes of the statute were to encourage:

1. Conservation of electric energy;
2. Efficient use of facilities and resources by electric utilities;
3. Equitable rates to utility customers; and
4. Development of cogeneration and small power production.

There is no doubt that in many states, such as California, the last objective has been achieved beyond all expectations. But, to date, there is little evidence that any benefits to utility ratepayers, reduced reliance on oil and natural gas, or increased efficiency in electric power production has occurred. In fact, in some jurisdictions, implementation of PURPA may actually have resulted in higher costs to ratepayers as a result of adopted pricing mechanism and increased use of oil and natural gas due to the encouragement of large fossil-fired cogeneration.

In view of the national experience to date, it seems appropriate for the FERC and the Congress to re-examine the implementation of PURPA. It does not seem desirable to have so subordinated the other important goals of PURPA to the goal of developing cogeneration and small power production. Certainly, the goals of conservation, efficient use of resources, and equitable rates for utility customers must receive greater consideration. Without equal consideration of these other goals, neither electricity ratepayers nor the nation will be well served.

When PURPA was designed by Congress, the general opinion was that QF development nationwide, although significant in absolute size, would be small relative to the traditional electric utility industry. In the environmental assessment conducted in conjunction with its rulemaking implementing PURPA, the FERC estimated that there would be 12,000 MW of QF capacity nationwide by 1995. However, in California alone, almost 16,000 of QF capacity could be deliverable by 1990. Thus, in view of subsequent developments, the impact of PURPA was considerably underestimated.

Any significant legislation carries the risk of unintended consequences. These include the inability to accurately gauge the overall magnitude of public response. PURPA is a case in point. It was designed to encourage and assimilate what was perceived to be a relatively small group of nonutility power producers, not to efficiently integrate a large independent power industry with the existing regulated utility sector. Nonethelass, despite its limited original intent and design capabilities, we are now faced with the task of applying PURPA to this more ambitious undertaking. Absent a careful re-examination, the result is likely to be serious system operation, reliability, and economic problems.

Despite all this, we do not believe extensive legislative action is warranted. The preponderance of problems with PURPA's Section 210 has not resulted from the statute, but from implementation by the FERC and the states. In many states, regulators have adopted rules so favorable to QF development that utility ratepayers have been adversely affected. Whatever the reason for this, it is certain that the QF industry frequently has been advantaged by the states' implementation, including the occasional willingness of some states to go beyond the provisions of PURPA and the FERC rules in seeking to stimulate QF development.

Southern California Edison

TABLE I-1

SUMMARY OF CALIFORNIA'S RENEWABLE/ALTERNATIVE ENERGY RESOURCES

AS OF MARCH 31, 1986

SOUTHERN CALIFORNIA EDISON COMPANY

	On-Line		On-Line Plus Committed	
Technology	No. of Projects	Nameplate Capacity MW	No. of Projects	Nameplate Capacity MW
Biomass	17	50	52	811
Cogeneration	61	645	101	2,918
Geothermal	4	97	31	925
Hydro	24	79	58	165
Solar	14	45	27	272
Wind	56	571	115	1,839
Other	0	0	0	0
TOTAL	176	1,487	384	6,930

PACIFIC GAS AND ELECTRIC COMPANY

	On-Line		On-Line Plus Committed	
Technology	No. of Projects	Nameplate Capacity MW	No. of Projects	Nameplate Capacity MW
Biomass	33	94	81	1,098
Cogeneration	95	611	204	3,789
Geothermal	2	81	12	175
Hydro	81	147	245	970
Solar	7	7	7	16
Wind	133	516	166	2,337
Other	1	1	5	25
TOTAL	352	1,457	720	8,410

SAN DIEGO GAS & ELECTRIC COMPANY

	On-Line		On-Line Plus Committed	
Technology	No. of Projects	Nameplate Capacity MW	No. of Projects	Nameplate Capacity MW
Biomass	1	3	8	119
Cogeneration	59	136	70	287
Geothermal	0	0	0	0
Hydro	5	5	6	6
Solar	13	5	15	5
Wind	10	2	10	2
Other	1	0	1	0
TOTAL	89	151	110	419
TOTAL RENEWABLE/ALTERNATIVE ENERGY RESOURCES	617	3,095	1,214	15,759

II

PURPA: INTENT AND FRAMEWORK

PURPA was enacted at a time when the nation was extremely concerned about potential disruptions in the international oil market and their impacts on national security and the economy. Reducing dependence on foreign oil supplies through conservation of oil and natural gas and development of alternative domestic sources of energy was a major national policy objective. The enactment of PURPA also came at a time when the forecast growth of demand for electricity remained relatively high, but many of the nation's electric utilities were beginning to experience major problems in financing and completing large generating facilities.

PURPA itself was a somewhat flexible piece of legislation that left a great many details to the FERC and the states to implement. In fact, as a result of several legal challenges, it appears that states may be free to adopt policies more liberal in their encouragement of QFs than those contained in PURPA and the FERC rules. Thus, a great many of the adverse impacts of PURPA have resulted not from its stated objectives, but rather from its implementation--specifically, the failure to properly implement all of the stated PURPA objectives in a fair and balanced manner.

A. Objectives of PURPA

It was thought that encouragement of cogeneration and small power production would improve the overall efficiency of electric power production, reduce the use of oil and natural gas, and provide greater diversity in the nation's sources of electricity. A perception also existed that there were several practical and regulatory barriers hindering the development of cogeneration and small power development. These obstacles included the reluctance of some utilities to deal with nonutility generators, difficulties project developers encountered in attempting to negotiate economically viable power sales contracts with utilities, and uncertainty about whether projects would be subject to regulation as public utilities.

The provisions of PURPA take several steps to deal with these concerns. First, they give the FERC discretionary authority to exempt QFs from state regulation of rates and financial activities, and from federal regulation under the Federal Power Act and Public Utility Holding Company Act. To qualify for these benefits, cogeneration and small power production projects must meet the requirements of PURPA Section 201 relating to fuel use, operating and efficiency standards, facility size, and facility ownership.

Second, PURPA requires utilities to interconnect with QFs, to provide them with backup service at favorable rates, and to purchase electricity at a rate which is the lower of the incremental cost to the utility of alternative electric energy or a rate that is "just and reasonable to the consumers of the utility, in the public interest, and nondiscriminatory". Congressional conferees stated that the phrase "just and reasonable to the consumers of the utility" be interpreted in a manner "which looks to protecting the interests of the electric consumer in receiving electric energy at equitable rates".

B. Implementation of PURPA

PURPA Section 210 mandated that the FERC prescribe within one year, and from time to time thereafter revise, the rules that it determined were necessary to implement the legislation. In early 1980, the FERC published its final rules. These rules covered: (1) the requirements for QF qualification (mandated by PURPA Section 201); (2) arrangements between electric utilities and QFs, including mandatory purchase rates; and (3) provisions governing state implementation. The specific provisions of some of these rules are discussed further in Section IV.

The regulatory framework set up by FERC is a hybrid federal/state system. FERC retained sole jurisdiction to certify facilities as QFs. The remainder of the regulations were to be implemented by state regulatory authorities. State implementation could be accomplished by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the FERC rules.

In initially promulgating their own rules, several states deviated from the provisions in PURPA, in some cases being less favorable, and in other cases more favorable, to the development of QFs. Subsequently, through court and other regulatory challenges, it was apparently established that states do not have the ability to promulgate rules less favorable to QFs than provided for by PURPA and the FERC rules. However, states may have the ability to institute, under their own authority, certain provisions more favorable to QFs than PURPA.

C. Conclusions

A great deal of the impact of Title II of PURPA on the electric utility industry and its customers can be traced to the manner in which it has been implemented by the FERC rules and by the individual states. As discussed at length below, we believe these implementation rules are, in several cases, at variance with the original intent of PURPA and ought to be revised. We believe this is especially the case because the original FERC rules were drawn up in anticipation of a much smaller response by QFs. Given the actual magnitude of the response, it would be prudent to reopen some aspects of these rules for further consideration. Recent statements by FERC Commissioner Stalon indicate an openness to undertake such a reconsideration:

> "This Commission has an ongoing responsibility to reassess the consistency of its rules in the light of the realities of electric power markets; rules that were proper to overcome inertia and initial resistance to the development of cogeneration may need change as the industry matures." (Applied Energy Services, Inc. vs. Oklahoma Corporation Commission, Docket No. EL85-25-000, 31 FERC Par. 61313 at 61711)

III

SUMMARY OF PURPA IMPLEMENTATION AND
QF DEVELOPMENT IN CALIFORNIA

Edison has been aware of the need to explore unconventional technologies to diversify its resource base for many years. The Company's first cogeneration venture, the 12 MW Garden State Project, came on line in 1967. In recognition of the need for further alternative resource development, Edison's research and development activities were formally centralized into one organization in 1971. The 1973 Arab oil embargo that quadrupled oil prices at a time when Edison was dependent on oil and natural gas for two-thirds of its generating capability stimulated additional investigations into alternative sources of generation. The Company expanded its R&D effort and began planning a series of demonstration projects to demonstrate the commercial viability of unconventional technologies. The second oil price shock of 1979-80 clearly indicated a need to reevaluate Edison's future energy resource options. In October 1980, the Company embarked on a bold and radically different resource strategy that placed heavy emphasis on renewable and alternative energy resources such as wind, geothermal, solar, fuel cells, small hydro, and cogeneration.

Edison's initial goal was to use alternative/renewable resources to satisfy at least one-third of its required resource additions (about 2,000 MW) by 1990. The federal government, particularly the Department of Energy ("DOE"), was very supportive of the Company's efforts. The Company's 10 MW Solar 1 generation station, the world's largest central receiver solar plant, was partially funded by DOE. Similarly, the 100 MW Cool Water Coal Gasification Project, the nation's only commercial-scale coal gasification plant, received financial commitments from the U.S. Synthetic Fuels Corporation at a crucial point in the project's development.

Additionally, by the late 1970s, regulators in California had already begun taking steps to encourage the development of cogeneration and small power production, independent of PURPA. The mandate of PURPA Section 210 requiring state regulatory authorities to implement the FERC regulations prompted the California Public Utilities Commission ("CPUC") to initiate the Order Instituting Rulemaking No. 2 ("OIR-2") proceeding in late 1980. In this ongoing proceeding, the CPUC and other regulatory bodies, the major electric utilities, and the QF industry have participated in an attempt to establish a framework for developing and assimilating the QF community in California.

A. Standard Offer Contracts

In January 1982, the CPUC issued a decision in OIR-2, ordering the major California electric utilities to file "standard offer" contracts for power purchases from QFs based on full avoided cost principles. The CPUC was not compelled by either PURPA or the FERC rules to adopt a "standard offer" approach, but chose to do so in its own rules implementing PURPA. This approach also gave QFs favorable standing and, coupled with federal and state tax incentives, acted as a tremendous stimulus to QF development. The standard offers were intended to prevent discrimination, provide uniform contract language where possible, and standardize costing methodologies for determining avoided cost among all utilities and all contracts.

Standard offers were to be available to all QFs. Such offers provided QFs with a contract in which all commercial terms were agreed upon in advance, thus significantly speeding up the power purchase contract negotiation process. Essentially, only the QF's signature was needed to complete execution. Additionally, QFs were still permitted to negotiate specialized contracts to better fit the needs of specific projects.

In 1982, the CPUC initially approved three standard offers based on "short-run" avoided costs:

1. Standard Offer No. 1 ("SO1") is for "as-available" QFs, those projects which cannot make a firm commitment to be available on-peak. The capacity schedule payments (paid on a ¢/kWh basis, and time-differentiated) may be revised annually, and time-differentiated energy payments reflecting current marginal utility fuel costs are revised quarterly.

2. Standard Offer No. 2 ("SO2") is for QFs who can make a firm commitment for up to 30 years to maintain an 80 percent capacity factor during summer peak hours. The energy payment is the same as in SO1, but firm capacity payments are fixed for the life of the contract and are made on a levelized basis (in $/kW). The payments depend on the initial year of QF operation and contract length. Capacity prices for future contracts are revised in utility general rate cases.

3. Standard Offer No. 3 ("SO3") is a simplified version of SO1 for QFs smaller than 100 kW.

B. Interim Long-Run Standard Offer

To provide further impetus to the California QF industry, the CPUC also determined that a standard offer based on a "long-run" avoided cost methodology was desirable to provide pricing certainty for QFs, assist them in obtaining project financing, and recognize the long-term value of new QF capacity in utility resource plans. The CPUC ordered the future development of such an offer at the same time it required the short-run offers. However, realizing that development of the long-run offer would take several years, the CPUC adopted an Interim Standard Offer No. 4 ("Interim SO4") in September 1983 that QFs could sign until a final version was developed. The interim offer was made available to both as-available and firm QFs. The capacity payment schedules were the same as under the short-run offers, but the energy payments were fixed, and based on a forecast of the short-run energy payment. There were three payment options open to QFs under SO4:

1. Payment Option 1: Energy payments were based on a forecast of avoided fuel costs. The payments were fixed for up to ten years, after which they would revert to actual short-run avoided cost for the remainder of the contract.

2. Payment Option 2: The energy payments for the Payment Option 1 forecast were levelized, providing higher payments initially to assist projects in getting started. The higher-than-avoided-cost initial payments were balanced by lower ones later in the project's life when its capital costs had been amortized. It was not available to oil/gas cogenerators.

3. Payment Option 3: Intended for oil/gas cogenerators, energy payments were calculated using a ten-year forecast of incremental energy rates (a measurement similar in concept to heat rates) and the current price of the utilities' marginal fuel (usually gas).

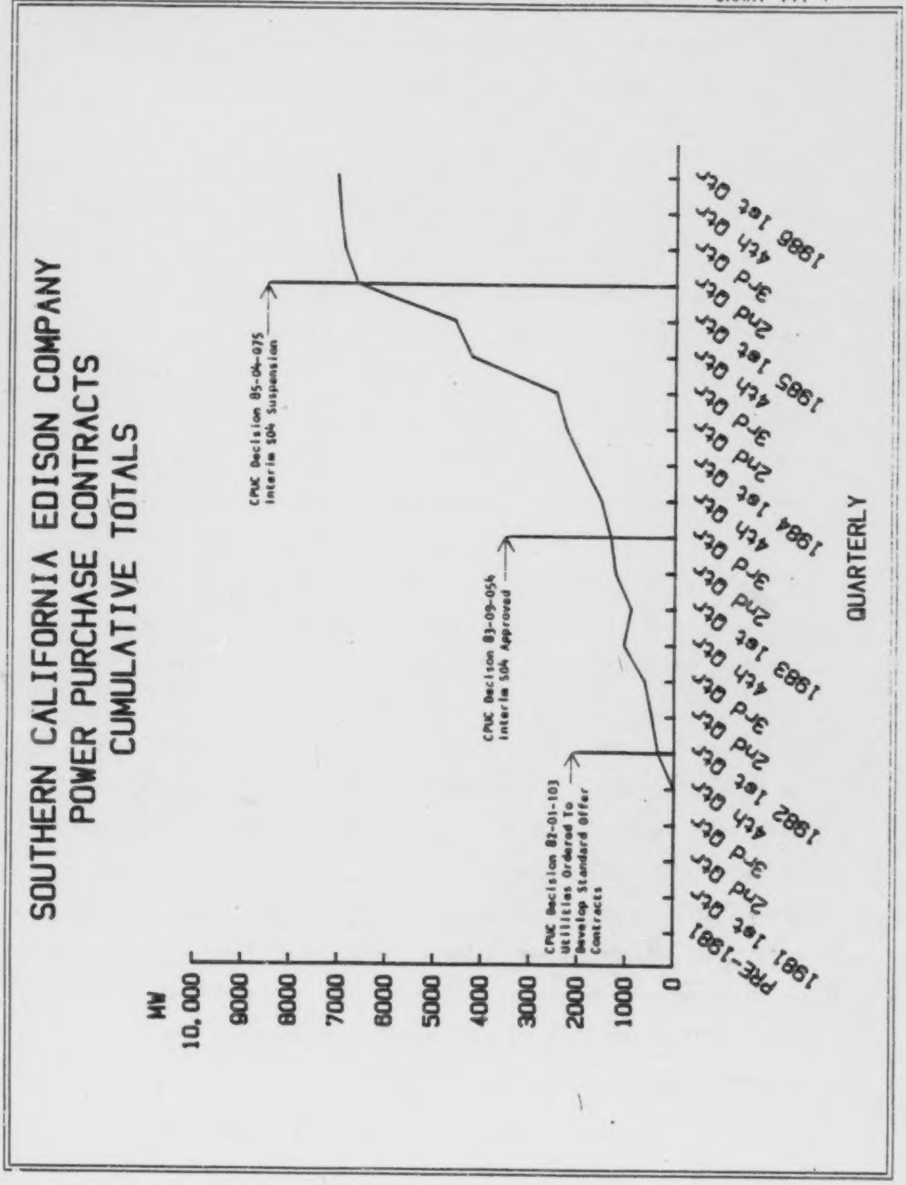
At the time Interim SO4 was adopted, the CPUC declined to place a cap on the total QF capacity allowed to take the offer. The utilities argued that a cap was needed to prevent energy and capacity forecasts from becoming out-of-date. But the CPUC anticipated that no more than 1,000 MW of QFs would sign the offer, which would obviate the need for such a cap.

However, QF response to Interim SO4 proved to be substantial, especially subscription of natural-gas cogenerators under Payment Option 3. In the year after its adoption, almost 2,600 MW of long-run contracts were signed. two-thirds of which were in Pacific Gas and Electric Company's ("PGandE") service territory. The magnitude of signups greatly exceeded the actual need for QF capacity, rendering the capacity price provisions obsolete, and exposing California ratepayers to overpayments to QFs.

In October 1984, the CPUC determined that emergency action was required. On its own initiative, it suspended the availability of PGandE's Interim SO4, Energy Payment Option 3, for oil and gas cogenerators larger than 50 MW. The CPUC reasoned that because this option could not be updated, and all QFs were paid the same rates without regard to their possible willingness to supply power at lower rates, little if any benefit was being passed on to ratepayers. If this option were continued, ratepayers would incur unreasonable costs by paying too much to too many cogenerators.

Southern California Edison

CHART III-1



SOUTHERN CALIFORNIA EDISON COMPANY
POWER PURCHASE CONTRACTS
CUMULATIVE TOTALS

Edison also experienced a QF oversubscription problem. Chart III-1 on the previous page demonstrates the dramatic increase in QF signups following the approval of Edison's Interim SO4. Over 4,000 MW of nameplate QF capacity was signed between the third quarter of 1984 and the second quarter of 1985. In addition to standard offer signups, Interim SO4's Energy Payment Option 3 also was being used as a basis for negotiating the pricing terms of nonstandard contracts, several of which were signed by large cogeneration projects.

In January 1985, Edison requested that the CPUC also suspend Energy Payment Option 3 of its Interim SO4. The Company's request was granted in February 1985. Finally, the CPUC became convinced that it was no longer possible to maintain ratepayer indifference between utility and QF power in view of continued capacity signups under Interim SO4. It completely suspended Interim SO4 for all major California electric utilities in April 1985, requesting comments on whether to make its suspension permanent or to reinstate it with reduced prices. In July 1985, the suspension became permanent until a final long-run standard offer with provisions for updating could be developed.

In total, 205 projects were signed under Edison's Interim SO4. These represent a combined nameplate capacity of over 3,600 MW, more than 50 percent of Edison's total QF contract capacity. Assuming that all of these projects become operational, ratepayer energy payments in excess of the current forecast of avoided cost are projected to be over $100 million in 1987, and will increase to a maximum of $650 million in 1995. These excess payments were going primarily to geothermal, biomass, and wind projects because payments to cogenerators are generally indexed to current oil and gas prices. A projection of annual ratepayer exposure to payments above the current forecast of avoided energy costs is shown on Chart III-2.

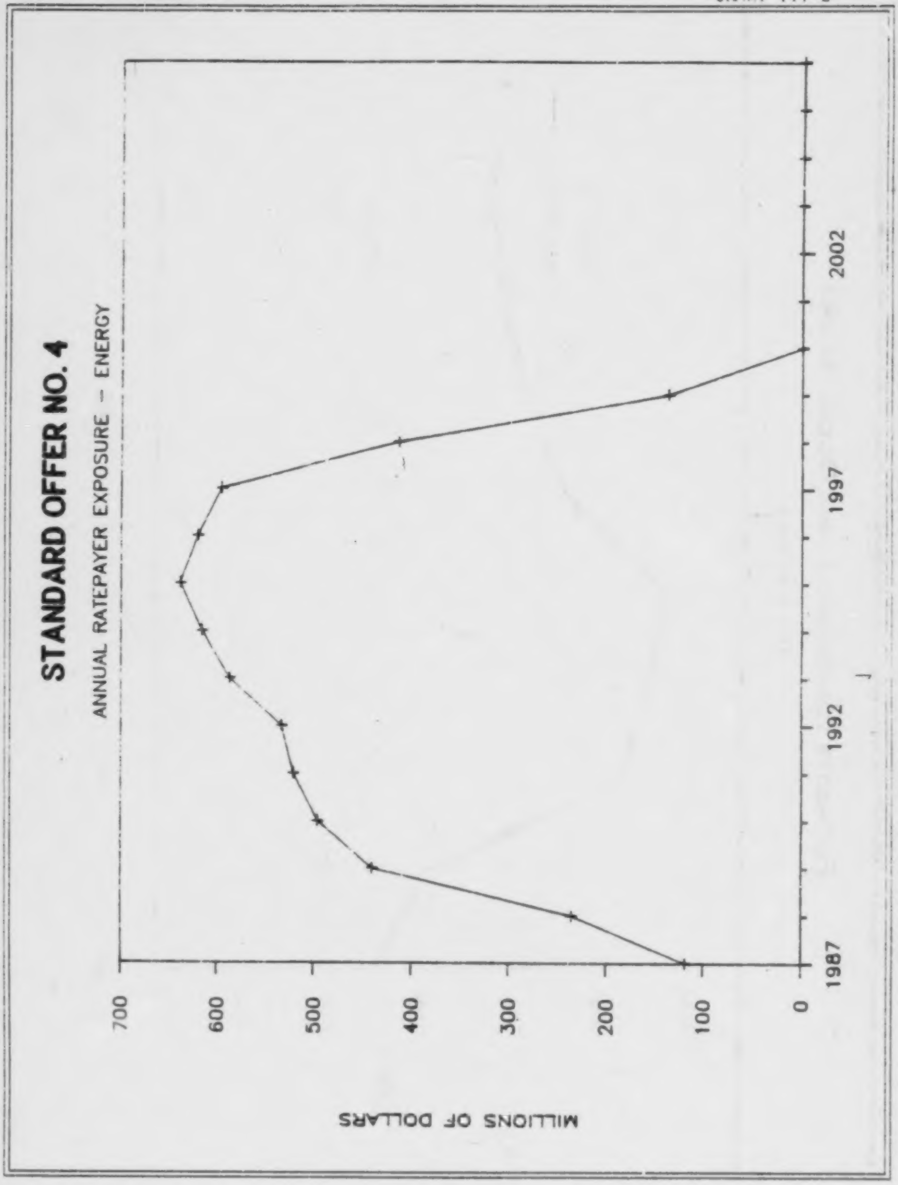
C. Final Long-Run Standard Offer and Suspension of Standard Offer No. 2.

While the interim S.O.4 ran its course, the CPUC continued to develop the final version of the long-run standard offer. In July 1985, the CPUC adopted a "simplified generation resource plan" costing methodology for determining long-run avoided costs. This methodology first identifies the optimal resource plan that the utility would use to meet system demand in the absence of QFs. Then, if the utility is able to defer or cancel some future plants because of QF power, the avoided cost price is based on the capital and operating costs of those avoided plants. If the QFs do not displace any future utility resource, the QF price is based on short-run marginal costs.

The latest phase of the long-run proceeding has focused extensively on contract provisions that deal with an excess capacity environment. Edison has noted that the very significant amount of QF capacity which it is obligated to accept has led to forecasts of sizable minimum load problems, in which the utility must actually turn away cheaper sources of power to purchase QF supply. Chart III-3 shows that minimum load occurrences on Edison's system are expected for 3,000 hours in 1990, and would be 5,700 hours if all contracted QF projects actually become operational. Edison and other parties to the long-run proceeding have emphasized the need for QFs with the ability to actually operate in a manner conducive to efficient utility system operation. Desirable operating characteristics include availability during emergencies, dispatchability, voltage support, and ability to schedule maintenance. Basically, QFs must be able to

Southern California Edison

CHART III-2

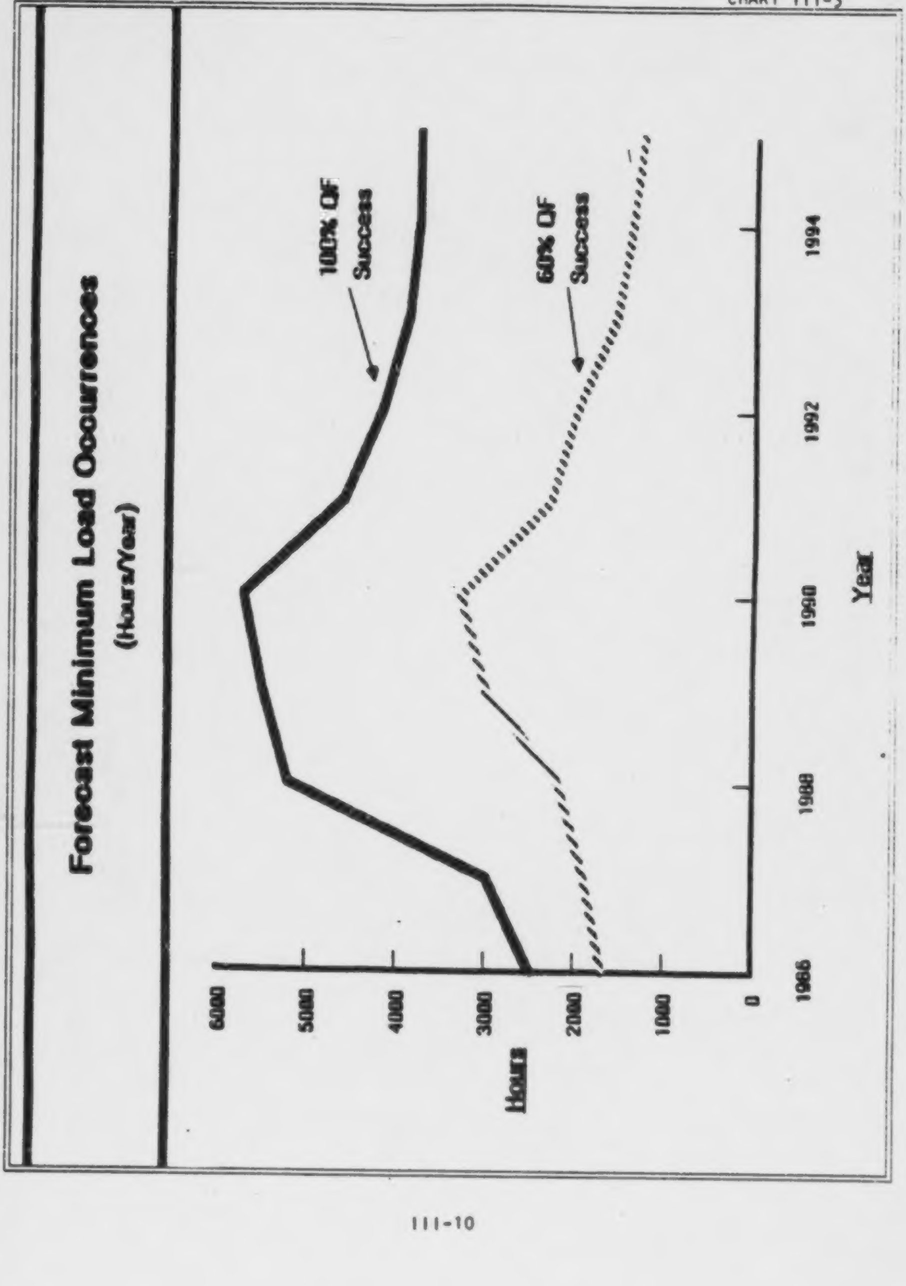


STANDARD OFFER NO. 4

ANNUAL RATEPAYER EXPOSURE - ENERGY

Southern California Edison

CHART III-3


Forecast Minimum Load Occurrences

(Hours/Year)

operate with reasonable similarity to the resources they would defer or displace. The Company currently has 167 MW (effective capacity) of dispatchable resources under contract, with a goal of 500 MW.

The QF oversubscription problem also caused the capacity payment tables for SO2 to become outdated and overvalue QF capacity. The only procedural mechanism for updating the tables is in utility general rate cases, which under the current rate case plan occur every three years. In recognition of this problem, and to prevent another QF "gold rush" like that which occurred with Interim SO4, the CPUC, on the motion of its own Staff, temporarily suspended SO2 in March 1986.

On May 7, 1986, the CPUC ordered continued suspension of SO2. The decision also gave further direction regarding the coordination in the long-run proceeding of matters such as capacity valuation methods, which affect all of the standard offers.

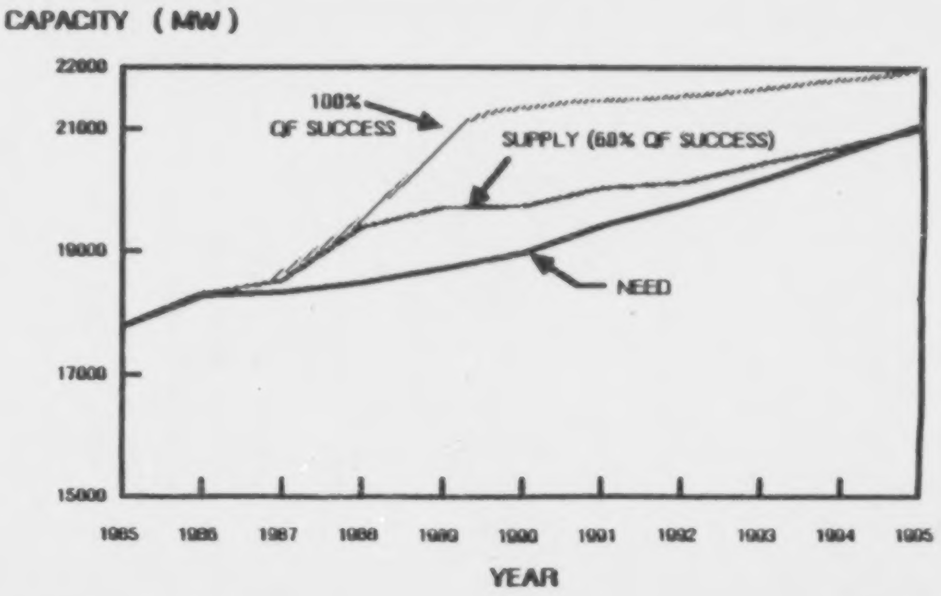
D. Conclusion

In retrospect, the policies established for implementing PURPA in California were well-intentioned. The QF industry was in its infancy early in this decade. No one conceived of the tremendous QF response to the standard offer approach. At the end of the first quarter of 1986, about 1,500 MW of QF capacity was producing power on Edison's system, with a potential for an additional 5,500 MW of nameplate capacity by 1991. However, it is doubtful whether this overabundance of resources, which exceeds Edison's needs into the late 1990s (see the chart on the following page), will provide long-term benefits to our ratepayers. The standard offer concept and the OIR-2 framework appear to have fallen short as regulatory vehicles capable of moderating QF development in excess of need, or developing a QF portfolio responsive to the operational requirements of the integrated utility electrical system. The absence of mechanisms for performing timely modifications to the standard offer capacity and energy prices has resulted in erroneous signals being delivered to the QF community, excess QF subscription, and adverse economic impacts on California ratepayers well into the future. Additionally, due to the large number of cogenerators in the QF mix in our state, California's resource base may well remain strongly raliant on fossil fuel.

Southern California Edison

CHART III-4

PLANNED RESOURCE ADDITIONS
1985 – 1995



IV

IMPORTANT ISSUES IN THE IMPLEMENTATION OF PURPA

Drawing upon our experience with the implementation of PURPA, we next discuss several of PURPA's difficult policy issues. The discussion is divided into three parts: fundamental industry structural issues, pricing issues, and QF qualification requirements.

A. Fundamental Industry Structural Issues

1. System Operability and Reliability

The system of qualification restrictions and avoided cost payment obligations under PURPA was not designed as a comprehensive framework to deregulate the electric power industry. It had the much more limited objective of encouraging the development of a small but significant industry of private generation to increase overall energy efficiency, conserve energy, and reduce national dependence on insecure foreign sources of energy.

The PURPA model, especially as implemented by the FERC, is a system designed to integrate with reasonable efficiency the planning and operation of third-party resources into a power system whose fundamental backbone consists of resources owned and operated by a vertically integrated utility. PURPA was not intended to, nor is the resulting structure particularly conducive to, supplant the fundamental coordination and integration achieved in this backbone of the system by a franchised utility entrusted with a legal obligation to serve all demand in its territory.

What most distinguishes the supply of electric power from other commodities is the need to balance supply with demand within narrow tolerances on a continuous basis in order to maintain service quality, reliability, and system integrity. In performing this function, the many components on an electric power grid are highly interdependent and must respond with a high degree of integration and coordination if electricity is to be supplied reliably at minimum cost. Among the many important coordinated functions which must be achieved are:

a. Preservation of electrical frequency standards and system stability by having a significant portion of generation able to follow load subject to central dispatch;

b. Dispatch of generation on an economic basis;

c. Planning and coordinating unit commitment and maintenance schedules;

d. Provision of adequate spinning reserve to assure system reliability;

e. Operating and planning to provide for adequate response to emergencies and subsequent system recovery; and

f. Scheduling of generation to achieve scheduled transfers of power across electrical systems.

Because electrical systems are complex and their efficient planning and operation involves thousands of interrelated reactions and decisions, responsibility for these decisions has been entrusted traditionally to a single vertically integrated utility charged with a public utility obligation within its franchised service territory. It is extremely doubtful that all of these planning and operating decisions could be made as efficiently and reliably through a system of arm's-length contracts rather than through integration under one organization.

This is not to say that there is not room to accommodate a significant QF community within the current industry structure. However, for a healthy third-party generation community to prosper, a vertically integrated host utility is needed. As the size of the QF community grows relative to the franchised utility, the integrity of the utility backbone becomes increasingly threatened, and the reliability of the system deteriorates. The ability of a system to accommodate a larger QF industry without suffering significant deterioration in system operability and reliability depends on many things, including suitable and extensive QF contract provisions. However, the dividing line will probably only be understood through practice. The bottom line is that ratepayers will bear the risks of this experiment.

2. Inadequacy of Price Signals Alone

Policy-making in some jurisdictions, especially California, has tended to view the QF integration problem as essentially a pricing problem. That is, to state the approach in its barest essentials, all that is necessary to solve the planning problem is to find the avoided cost level at which QF supply is sufficient when added to utility supply to balance total supply and demand. Solution to the operating problem, in turn, is pursued by time differentiating these rates. Such a policy model takes a few simplistic insights of economic theory and attempts to elevate them to a solution to highly complex technical and economic problems. Rather than providing a final and workable solution, it is really only a useful starting point.

Encouragement to view the problem as purely a matter of pricing is to a large extent conveyed by the FERC rules themselves. By mandating full avoided cost payments and then allowing adjustments to be made for certain specified QF operating characteristics, the rules give the impression that virtually all performance dimensions can and should be "priced out", and that such a system should be sufficient to assure efficient system integration. But utility planning and operating problems are complex and multidimensional. It is unrealistically optimistic to believe that these processes can be rationally guided by a system of multidimensional prices, even if applied on a real-time basis.

The deficiencies of a pure pricing system are also felt in the resource planning process. The current system of standard offer contracts in California, based on offering the same avoided costs to all QFs on a first-come, first-served basis, has resulted in a technological mix of QFs which many have questioned. Concern exists that the QF resource mix, composed of considerable quantities of natural-gas-powered cogenerators, is not consistent with overall state fuel use policies. This criticism simply highlights the fact that the relevant dimensions of resource value (e.g., dispatchability, fuel diversification, etc.) are not, and possibly cannot be, adequately incorporated into a standard pricing system and should be supplemented with additional contractual controls of various kinds.

3. The Utility Obligation to Serve

A final fundamental structural change resulting from PURPA is that the meaning of the utility's traditional obligation to serve becomes progressively vague as the size of the QF industry grows larger. This results in greater financial and service reliability risks for ratepayers. No longer can the utility by itself, using its own assets, provide reasonable assurance of continued service. The fundamental purpose of PURPA to allow utilities to defer construction of power plants essentially undercuts the utility's ability to self-sufficiently satisfy its service obligation. Instead, it must rely on QFs, plus higher reserve margins, if necessary, to meet its service obligation.

The bottom line is that both the utility and its ratepayers are subjected to greater risks. The performance and persistence of QFs, especially across a wide range of general economic conditions, is not the same as a utility's, nor is it well understood. A QF's obligations to the public are contractual and relatively limited. On the other hand, a utility's obligations are more extensive and established by a totally different body of laws and regulations. If a QF's economics turn sour, the QF can simply stop supplying power and suffer a comparatively limited economic loss. But such an option is not available to the public utility. Thus, as QF power assumes a larger share of total production, ratepayers will be involuntarily assuming more risks as they unwittingly participate in an experimental modification of the traditional electric utility structure and with it the traditional service obligation.

B. Pricing Issues

1. FERC's Full Avoided Cost Rule

One of the most controversial aspects of the FERC's rulemaking implementing PURPA was the provision requiring utilities to pay QFs their full avoided cost of production. PURPA Section 210 directed the FERC to establish a pricing rule which would achieve the goals of the legislation by balancing the competing objectives of achieving an efficient use of energy resources, encouraging QF development, and benefiting utility ratepayers. It further directed the FERC that such a price should not exceed the level of a utility's incremental costs. After deliberating on the matter, the FERC found that the maximum rate allowable, namely full avoided cost, also happened to be the price that appropriately balances the competing objectives of the legislation.

Criticism of FERC's full avoided cost rule is well-trod ground, and we will not attempt here to be exhaustive in our remarks. FERC's decision to adopt a full avoided cost standard is not wholly surprising, especially because the QF industry was viewed as an infant industry at the time the FERC rules were promulgated.

Nonetheless, there is good reason to believe the full avoided cost rule was shortsighted and ought to be modified, especially in light of the subsequent growth of the QF industry.

If one is willing to ignore some of the complex economic dimensions of integrating resources into a unified power system and resort to the simplest economic textbook models of supply and demand, then the full avoided cost rule has some appeal. If one is willing to make enough simplifying assumptions (especially regarding risk, uncertainty, and transaction costs), it is straightforward to show that production costs are minimized when the marginal costs of production are equated across all available sources of supply. When utilities purchase power from other suppliers at the utility's marginal cost, this tends to result in production by all suppliers who can produce at costs less than or equal to the utilities' marginal costs. This tends to result in an efficient allocation of electricity production.

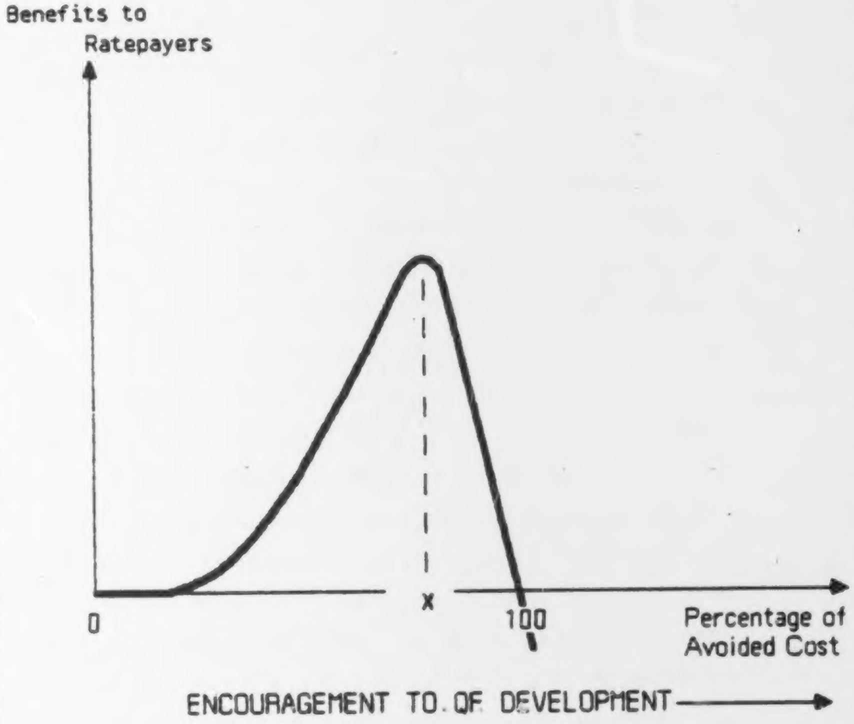
Given the appeal of such a simple policy model, it is not altogether surprising that the FERC initially adopted this approach. But it is important to realize its shortcomings. The full avoided cost rule, though possibly the simplest, is not the only available option which may lead to an efficient allocation of production. Indeed, other options are available which would encourage an efficient level of QF production while also passing along benefits to utility ratepayers.

Simply stated, the problem with the full avoided cost rule is that all QFs are paid the same rates without regard to their possible willingness to supply power at lower rates. The difference between the minimum price that a QF would accept and still produce and the amount it actually gets paid is an economic surplus. Under the full avoided cost rule this economic surplus is wholly captured by QFs and little, if any, benefit is passed on to consumers who, in the absence of QFs, would simply have paid for the utility's power an amount equal to the avoided cost payment otherwise made to QFs (assuming that avoided cost itself is not driven up by the presence of QFs, as we discuss in Section IV.B.3, below).

At least two general alternatives to the full avoided cost rule are available: a fixed percentage of full avoided costs, and some sort of shared-savings arrangement. A brief discussion of these alternatives is instructive in understanding the deficiencies of the full avoided cost rule. The trade-offs among policy goals in choosing an appropriate percentage under the fixed percentage approach are illustrated in Figure IV-1 (see below). At very low percentages there is very little QF development and consequently few benefits to ratepayers. As QF rates are raised, more QFs enter the market and ratepayers benefit even more. At some percentage of full avoided cost (X percent in Figure IV-1), the benefits to ratepayers are maximized. Beyond this point, higher QF payments do not elicit sufficient incremental QF supply to offset the additional payments made to those QFs who would have been willing to supply at lower prices. In other words, at percentages in excess of X percent, sufficient economic surpluses are transferred from ratepayers to QFs that offset the benefits of increased QF supply. Thus, as rates exceed X percent of full avoided cost, benefits to ratepayers steadily decline, reaching zero at 100 percent and becoming negative at rates in excess of full avoided costs.

FIGURE IV-1

TRADE-OFFS AMONG POLICY OBJECTIVES UNDER THE FIXED PERCENTAGE APPROACH



Looking at the selection of the level of the fixed percentage in a slightly different way, the problem of pushing this percentage to the full 100 percent level is that the incremental cost of QF power to customers gets very expensive. This is illustrated with a simple example in Table IV-1 (see below). At various purchase prices (Column 1), various levels of QF power are supplied. However, the marginal cost of the power to ratepayers will generally exceed the rate paid to QFs. This results because the effect of raising prices to QFs to bring about increased QF supplies requires higher payments to all QFs, including those willing to supply at lower prices. For example, in Table IV-1, if the full avoided cost level were at 5¢, the incremental cost of QF power to ratepayers would not be 5¢ but rather 9¢. That is, the effect on the ratepayer of raising the purchase rate from 4¢ to 5¢ in order to increase QF supply from 400 to 500 units is that total QF payments increase from $16 to $25, a difference of $9. Thus, the incremental cost to the ratepayer of the last 100 units of QF supply is 9¢, a figure considerably in excess of the 5¢ avoided cost level at which power could have been purchased from the utility.

TABLE IV-1

Purchase Price	QF Power Supplied	Total Payments	Marginal Costs
1¢	100	$ 1.00	1¢
2¢	200	4.00	3¢
3¢	300	9.00	5¢
4¢	400	16.00	7¢
5¢	500	25.00	9¢

Through PURPA Section 210, Congress instructed the FERC to formulate a pricing rule which would balance the competing goals of the statute, including provision of benefits to ratepayers, encouragement to QF development, and promotion of conservation and resource efficiency. In adopting the full avoided cost rule, the FERC recognized, as illustrated in Figure IV-1, that the rule would not directly provide any rate savings to electric utility consumers, but deemed it more important that the rule provide the largest incentive to the development of an efficient level of QF supply.

Rather than trying to neutralize the possible monopsony power (i.e., purchasing power) of the utility, as the full avoided cost rule does, a shared-savings incentive approach harnesses the utility's monopsony power for the benefit of the ratepayer. The utility is provided an incentive to act as an agent for the ratepayer and strike the best possible deal on their behalf. Many incentive designs are possible. One simple one would be to allow the utility to retain some percentage (e.g., 25 percent) of the difference between its full avoided costs and contract payments to QFs.

By moving away from a fixed percentage approach and toward some shared-savings incentive approach, FERC can escape the dilemma of having to choose between stimulating QF development and providing ratepayers with direct benefits. An imaginative shared-savings approach would encourage QF development while passing significant benefits along to ratepayers.

2. Capacity Payments

Rates paid to QFs are set inappropriately high by state policies when a utility is required to make capacity payments even though adequate capacity exists on its system. In some states, utilities' reserve margins are seemingly ignored. In other cases (e.g., California), QF resources are deemed to have capacity value, even at relatively high reserve margins, based on the concept of "shortage costs". According to this concept, additional QF resources have some capacity value, even at high reserve margins, because they reduce the probability of a system generation shortage.

The payment to QFs for capacity value in the absence of a deferred or avoided resource expenditure is clearly contrary to the FERC rules. Under the FERC rules, utilities can be required to pay QFs for the capacity value of their projects only when the availability of such capacity allows the utility to reduce its own capacity-related costs by deferring construction of new plant or by deferring or avoiding firm power purchases. Thus, states ordering capacity payments to QFs in the absence of needed resources, or based only on "shortage costs", would seem to be acting beyond the mandate of PURPA.

There are two major problems with paying for capacity in the absence of need. The first and most obvious problem is that ratepayers suffer by having to pay power costs in excess of those they would have paid in the absence of QFs. The second problem is that, as a consequence of prices that are essentially in excess of avoided costs, scarce national resources which could be put to better uses in other places or at later times are diverted to the QF industry. The clear result is economic waste and higher rates to utility customers.

A problem closely related to paying too much for capacity is that of paying too soon for capacity. Even though two pricing formulas may pay the same present value amounts for capacity over the life of a QF contract, one formula may provide for a more efficient staging of these payments over the life of the contract. The proper timing of capacity payments is especially important because, under the PURPA model, utility purchase obligations are rigid; the major open issue is price. This makes price a significant policy variable in controlling the timing of QF development. When resources are developed either too soon or too late, the result again is economic waste. Thus, setting the right intertemporal pattern of capacity prices is especially important in influencing QFs to delay or accelerate project development to meet actual capacity needs. The practice in many state jurisdictions of levelizing capacity payments seriously jeopardizes the efficient functioning of price signals in rationalizing the on-line dates of QF projects. Levelization, by shifting a portion of capacity payments into earlier years, stimulates QFs to come on-line ahead of when they are really needed.

3. Providing for Valuable Operating Characteristics

An essential characteristic of the production of electricity, distinguishing it from most other products, is that supply must be kept in continuous balance with demand to maintain the quality of the product. This requires a high degree of integration and coordination in planning and operating an electrical system. QFs that can contribute to solving this coordination problem are more valuable than those that cannot. If a QF does not contribute at all to this supply-side coordination, then at best it is simply "negative load" from the viewpoint of planners and operators; that is, the QF supply may be delivered when not needed, and unavailable when critically necessary. Depending on the load characteristics and predictability of this "negative load", it will generally require planners to install greater generation reserves and require operators to run higher levels of spinning reserves. It may even have the effect of forcing utility engineers to plan units that cost more than those they would have installed absent QFs--peaking plants, for example--a phenomenon which could perversely result in rising utility avoided costs and subsequent development of still more poorly integrated QF capacity.

When the QF industry was foreseen as a relatively small industry, there was not so great a need for QFs to participate actively in supply-demand coordination activities. A small amount of somewhat unpredictable "negative load" could be accommodated on a utility's system without jeopardizing system reliability or substantially increasing costs. In this context, it was probably reasonable to see the provision of favorable QF operating characteristics as primarily a pricing issue. Furthermore, the pricing issue was not so much one of trying to control the integrated planning and operation of a utility system as it was simply trying to avoid paying for a service that was not received. Thus, the model adopted in the FERC rules was simply to price out these operating characteristics and allow reductions in avoided cost rates if they were not provided.

For utilities with unexpectedly large amounts of prospective QF power, such as the California utilities, it is especially important to have QFs provide the operating characteristics necessary for effective supply-demand coordination. In recent proceedings before the CPUC, Edison has advocated that the availability of pricing options, as well as the payment rates contained therein, be based on the ability and willingness of QFs to provide certain operating factors which are reasonably accurate in matching the needs of the system and the characteristics of the deferred or avoided utility resource. These factors include:

a. Availability during emergencies;

  (1) Ability to remain connected to the system;

  (2) Ability to come on line quickly or change load during an emergency;

b. Ability to assist in system voltage control by adjusting reactive power production;

c. Ability to schedule maintenance; and

d. Dispatchability.

The main problem with the FERC's emphasis on "pricing out" QF operating characteristics is that it seems very doubtful that a pure price signal can best achieve the complex coordination task facing a utility system with a substantial QF supply component. In this context, total reliance on price signals is inappropriate and inadequate to the task. A variety of direct operational controls that include the factors listed above is necessary to coordinate production and assure system reliability. As the size of the QF industry becomes even more significant, it is essential that a substantial portion of QF contracts contain such provisions to assure the reliable and cost-effective operation of the electrical system. Persistence in thinking about the problem as basically one of price is not very useful. It is a control problem, and price by itself is frequently not the best mechanism for controlling complex interdependent systems where reliability is critical.

4. Updating of Pricing Provisions

In general, calculated avoided costs can change and become obsolete for one of two reasons: first, the cost relationships on the utility's system may change due to changes in resource availability or fuel prices; second, the margin at which the utility's avoided cost is calculated may change due to a change in forecast loads or QF contract subscriptions.

It may seem obvious, especially after the fact, but if there is one thing to be learned from our experience in California, it is the need to have an expeditious method of modifying or withdrawing standardized pricing offers which have become outdated. There are several ways in which ratepayers can be protected from paying too much due to the obsolescence of a standard offer contract. For instance, definite "sunset" dates can be set for the availability of any price offers. Second, because any avoided cost calculation is necessarily applicable only within a certain megawatt range of QF subscription, megawatt limits can be specified governing the maximum quantities of QF contracts which can be signed before it becomes necessary to recalculate a new price offer. Alternatively, a series of successively lower avoided cost price offers can be calculated, each with its own megawatt ceilings on contracts. Once one pricing block is filled, new contracts are automatically offered at the next lower price block. Still another way of protecting ratepayers from QF oversubscription and overpayment is to periodically place a specified increment of available capacity up for bid in an auction.

C. Eligibility Restrictions for QF Status

1. Fuel Use Restrictions

Another of the most controversial aspects of PURPA implementation has been FERC's rules governing use of fuels by cogenerators and small power producers. FERC decided not to impose any limitations on fuel use for cogenerators, while basically ruling that, for small power producers, the aggregate use of oil, natural gas, and coal by a facility must not exceed 25 percent of its total energy input.

To many observers, the pattern of fuel use restrictions established by FERC is a difficult to reconcile mixture of provisions. This may have been the result of diverse motives--in some cases based on environmental considerations, in other cases concern for economic efficiency, and in still other cases on a philosophical preference for small, decentralized, renewable resources. It would seem beneficial to reassess the current fuel restrictions contained in the FERC rules in the light of changing energy policy objectives, especially if a coherent set of objectives can be specified.

We believe that mandatory purchase obligations at full avoided cost prices is a preferential arrangement which should not be extended to all independent power producers on an indiscriminate basis. If this arrangement is to be continued (and we believe that this is not generally advisable), it should certainly be restricted to specific fuel sources and technologies consistent with national energy goals. We continue to be concerned with the FERC rules that permit small power producers to use oil and natural gas for up to 25 percent of their fuel input. Some small power producers have abused this provision. If one goal of our national policy continues to be conservation of these fuels, then the limit should be reduced, perhaps to the 10 percent range. On the other hand, if conservation of these scarce fuels is no longer a national objective, then the fuel and technological preferences in PURPA should be reassessed accordingly.

2. Operating and Efficiency Standards

One of the basic objectives of PURPA was to encourage cogeneration as a means of making more efficient use of energy resources. FERC has imposed operating and efficiency standards in an effort to prevent qualification of "bogus" cogenerators designed to produce only nominal amounts of useful heat or power simply to qualify for PURPA benefits. The rules specify that at least 5 percent of a "topping-cycle" cogenerator's total energy output must be in the form of useful thermal energy. Furthermore, FERC has applied efficiency standards to oil and gas cogenerators which require that the sum of useful power output plus one-half the useful thermal output must be greater than 42.5 percent of the cogenerator's annual energy consumption.

The problem with these FERC rules is that they seem designed more toward defining the "ragged edge" identifying clearly unacceptable cogenerators, and less toward promoting energy conservation. The result may even be the promotion of an overall increased use of gas and oil. An increasing number of cogenerators are using extraction turbines in a clear attempt to maximize electricity production with a minimal use of waste heat. For instance, a commercially available combined cycle power plant with an extraction turbine can easily meet the FERC's efficiency standards while combining only minimal thermal uses. At best these "PURPA machines" are simply contrivances designed to use a legitimate cogeneration activity to bootstrap a facility 19 times its size into QF status. That is, the QF in such cases can be thought of as two separate facilities: one a true cogenerator, and another, up to 19 times as large, a conventional electric power generator that would not otherwise be eligible for QF benefits, including freedom from public utility regulation.

Some would argue that no harm would be done by simply allowing conventional electric power generation configurations to qualify for QF status under PURPA. We have two general responses to this. First, if it remains a matter of national policy to conserve oil and gas and make more efficient use of energy resources, then qualifications for preferential treatment under PURPA ought to be designed to promote these objectives. As currently designed, they do not. Second, as previously discussed, if the national objective is to open up the generation of electricity to nonutility suppliers on a broad basis, then the Congress ought to carefully examine the issue and speak directly to it. PURPA was not originally designed with this objective in mind and is not currently well-designed to protect ratepayers if it were extended to this role by FERC's administrative fiat.

3. Utility Ownership Restrictions

Section 201 of PURPA states that a QF may not be owned by a person primarily engaged in the generation or sale of electric power. In its rules, the FERC prohibited electric utilities, electric utility holding companies, and subsidiaries from owning more than 50 percent of the equity interest in a QF.

The utility ownership restrictions have been among the most controversial in the implementation of PURPA. We see several good reasons for allowing greater utility participation: (a) more efficient integration of QF facilities; (b) more rapid development of advanced technologies, especially coal technologies; (c) more equitable treatment of the utility industry relative to other industries which have full QF participation rights; and (d) availability of more capital to the QF market. There are many huge, Fortune 500 corporations currently actively involved in the QF industry. We see no compelling reasons to exclude utility participation, either directly or through subsidiaries.

V

RECOMMENDATIONS

Our recommendations for potential modifications to the FERC's rules implementing Title II of PURPA are not designed to result in regulations which are highly technical, overly specific, or unnecessarily complex. Such an approach is tempting, as it can preclude much of the potential for the state implementation problems we have seen, but also is likely to yield a policy which is incapable of reflecting the rapidly changing energy market climate or the different regulatory situations across the nation. Rather, our approach is based upon the investigation of a few broad policy guidelines which can provide a sufficiently large and sturdy framework to support PURPA's intent, while leaving considerable discretion with FERC and the states.

Edison recommendations are divided into two general areas of concern: pricing policy and QF qualification criteria.

A. Pricing Policy

1. The Avoided Cost Standard

As discussed more fully in Section IV.B.1, FERC's full avoided cost standard is effective as an incentive to QF development, but provides no direct rate benefit to utility ratepayers. The magnitude of QF development throughout the nation clearly demonstrates that the QF industry is no longer an "infant", and no longer requires mandatory and preferential pricing policies which excessively promote supply. In light of substantial QF development to date and in keeping with PURPA's goal of providing for ratepayer benefits, Edison recommends that investigation be undertaken of various shared-savings approaches to QF pricing. The FERC rules should be specifically amended to recognize the validity of such approaches, and to more clearly define avoided cost as a reasonable ceiling and touchstone for state implementation, not an absolute level.

2. Capacity Payment Restrictions

As we have previously discussed (Section IV.B.2), many states have exceeded PURPA's mandate and the FERC rules by requiring capacity payments to QFs in the absence of deferrable or avoidable utility resources. This strategy has resulted in ratepayers incurring higher costs than they would have without QFs, and has wasted scarce resources. Both outcomes are contradictory to PURPA's intent. Edison recommends that FERC's rules be amended to clearly direct state regulatory authorities to allow capacity payments for QFs only for and in years in which deferrable or avoidable utility capacity can be specifically identified. In short, payments for capacity should be precluded for years in which forecast utility reserve margins, absent additions not yet committed, are already adequate. When margins are forecast to be inadequate, states should not undertake levelizing or "front loading" capacity payment schedules which effectively pay for capacity too early, and thereby encourage QF development in advance of actual need.

3. Matching of QF Operating Characteristics to Utility System Needs

The emergence of a very large QF industry has led to problems for utility planners which were unanticipated at the time of PURPA's enactment. The absence of defined operating roles for QFs can, as discussed in Section IV.B.3, jeopardize utility system reliability and/or lead utilities to make resource decisions more costly than if operating characteristics were certain. For example, if QFs elect to build principally nondispatchable resources, utility planners must elect to install more dispatchable resources, regardless of cost. This approach is both inequitable to ratepayers and inefficient. FERC's approach to this problem, the allowance for pricing variations for different operating characteristics, has been inadequate to perform the complex demand-supply matching function necessary to maintain electric system resource efficiency.

Edison recommends that FERC regulations be modified to provide for the development of mechanisms which require a reasonable degree of matching of operating characteristics between QFs displacing utility resources and the displaced resources themselves.

B. QF Qualification Criteria

1. Restrictions on Fossil Fuel Use

FERC rules regarding fuel use by QFs are designed, basically, to restrict the use of fossil fuels by small power producers to 25 percent of total energy input (Section IV.C.1). If PURPA's intent to reduce dependence on finite and volatile fuel supplies remains an important national policy priority, then Edison recommends reducing this limit, with 10 percent a suggested level. If conservation of fossil fuels is no longer an objective, then the need for fuel restrictions should be reassessed.

2. Efficiency Standards for Cogenerators

As we explain more fully in Section IV.C.2, FERC's nominal efficiency standards for cogenerators (5 percent of total output in the form of useful thermal energy) have allowed for the development of a generation of bogus "PURPA machines", which are basically conventional generating stations with minimal cogeneration functions appended to skirt utility regulation. In keeping with PURPA's objectives of conserving oil and gas and making more efficient use of energy resources, Edison recommends that this criterion be substantially tightened. Those independent power production facilities whose primary business purpose is the generation of electricity should be subject to the same regulatory obligations, costs, and opportunities that traditional utility enterprises bear--or else should not receive the pricing preference accorded by a full avoided cost standard which assumes that utility and independent facilities are essentially equivalent to the ratepayer.

3. Restrictions on Utility Ownership

As explained earlier (Section IV.C.3), the FERC rules impose a 50 percent limitation on utility ownership of a QF. This limitation had a reasonable rationale at the time it was promulgated. However, the QF industry is no longer an infant industry. We believe utilities should be allowed to participate more fully in QF projects, either directly or through their subsidiaries.

The **Chairman**. Thank you, gentlemen. I have had the opportunity to look at the prepared statements, and I appreciate the amount of detail that has been included in the prepared statements which I will hope will enable the committee to understand and deal with the question in more precise detail than general statements would do.

Mr. Simmons, one of the features of PURPA, which has led to some of the problems that you outlined, was simply our reliance in the statute upon the functions of the State regulatory commissions.

Mr. Lanham mentioned the fact there are regional differences; there are differences almost system by system across the country. Yet a lot of problems that have come seem to come from applications by the State regulatory commissions. Is that a fair statement?

Mr. **Simmons**. I think it certainly is. I think there is a lot of variations between the States and their approaches, particularly the avoided cost calculations. I think that there certainly needs to be some evaluation of these variations in some form, particularly, I think the FERC could do a good function by having a notice of intent to collect all this information and to evaluate it and to put out some more definitive guidelines specifically on the calculation of avoided costs by each State.

The **Chairman**. There are also, in establishing avoided costs, the questions of capacity and energy credits. Has there been a wide variation in the application of those standards?

Mr. **Simmons**. There certainly has, and it has been interpreted in many different ways in many different States, and particularly in Texas, the avoided costs, particularly for most systems and particularly for Houston Lighting & Power has been on the basis of some future lignite-based plant which certainly has a large capital cost and large carrying cost associated with it.

So, you end up paying avoided costs for capacity payments based on a high capital cost power plant which we have planned for some time in the future, yet the cogenerators turn around and instead of building a plant with some solid fuel, lignite or coal, put in a very low cost plant, burning natural gas, to take advantage of the temporary low cost of natural gas we have now, which definitely cannot be relied on for some 30 to 40 years, which would be the case for a lignite or solid fuel plant.

The **Chairman**. On page 14 of your statement, you recommend that QF status be granted to natural gas cogenerators only if they have proven reserves and backup fuel sources. Has the whole industry taken a position on that subject, or is that just the position of Houston Lighting & Power?

Mr. **Simmons**. That is the position of Houston Lighting & Power, and I think we are trying to point out here the difference in relying on a natural gas-fired cogenerator which cannot guarantee that they will be here for some 30 to 40 years; cannot guarantee availability or the price stability that you would have if you had a solid fuel plant where you would have long-term contracts for the coal and some assurance that the fuel would be available and some stability in the prices in the future.

The **Chairman**. Mr. Simmons, on page 3 of your statement, at the end of the first paragraph, you conclude by saying that your company and EEI believe this problem can and should be corrected through regulatory action without need for legislative changes. Is that correct?

Mr. SIMMONS. Yes, it is; and I think that the FERC has the latitude to interpret the legislation to correct most of the changes. All of the changes that I have laid out here; yes.

The CHAIRMAN. Mr. Lanham, the Idaho commission recently lowered the avoided cost rate. That has narrowed the problem somewhat for your company, is that correct?

Mr. LANHAM. Yes, Mr. Chairman, it has. The problem still exists, of course, is the surplus of energy and the availability that we could buy in the next 10 years' supply of need for in essence just our fuel costs. BPA has, just this week I think, reduced their cost to southern California to seven-tenths of 1 cent, to 7 mils.

The CHAIRMAN. What is the current avoided cost that you are paying, as calculated by the Idaho commission?

Mr. LANHAM. For 1986, or 1987 and 1988, it will be 4.5 cents, and then it increases to 4.7 cents. That will be for all of the new projects.

The CHAIRMAN. Six to seven times the amount of cost of the power that BPA is now selling to California?

Mr. LANHAM. That is exactly right. It doesn't give me the opportunity—and Mr. Simmons is right—FERC could correct that. It doesn't give me the opportunity to purchase that energy. I have to buy from the cogenerator.

The CHAIRMAN. You calculated the cost to the ratepayers of purchases from currently operating QF's at $1.2 billion over the life of the contracts. Is that just the total contract payments to them?

Mr. LANHAM. Total contracting of all of those projects that we have signed projects for and are on line.

The CHAIRMAN. Mr. Hebert, on page 8 of your statement, you calculate the steam requirements of industrial customers and derive from that a generation potential for electricity. How is that calculation done?

Mr. HEBERT. We surveyed the steam needs of the industrial customers, 5 years in the future; and the steam requirement of those customers could cogenerate in excess of 4,000 megawatts of electric power, and that is how it was calculated.

The CHAIRMAN. Based upon that steam requirement, you calculate the amount of electricity that could be produced in cogeneration with that steam requirement?

Mr. HEBERT. Yes, sir.

The CHAIRMAN. What variations do you see in thermal efficiency in some of the cogenerators? Are there wide variations?

Mr. HEBERT. We think there are, because it is difficult to tell because we don't have access to the actual data and we don't have a part in the licensing process.

The CHAIRMAN. Who does have the actual data?

Mr. HEBERT. My understanding is that the FERC does. They have the data that has been filed.

The CHAIRMAN. And you do not have access to that data?

Mr. HEBERT. No, we don't. It is not possible to calculate precisely what the efficiencies are. We believe though that the PURPA machines, as they are common referred to, increase efficiency of power plants by about 5 to 7 percent, which is not the meaningful amount envisioned by the original legislation, I don't think. But the increase is from about 35 or 37 percent efficiency to about 42 or 43 percent.

Mr. SIMMONS. Mr. Chairman, if I may comment on that question. We have made an analysis of most of the cogenerators in our area and, if you will take an optimum sized cogenerator, one who takes the steam requirements and simply utilizes the surplus electricity that would be produced by that, you will get a cogeneration efficiency somewhere approaching 80 percent.

This is what is commonly referred to by the cogenerators that they have twice the efficiency of the electric utilities who are in the high 30 percent range generally. Some of the PURPA machines in our area, we have some machines that are down in the low 40 percent range where they have leveraged the amount of electricity some 7 to 10 times as much. So they are using enough fuel to produce 7 times the electricity that they would if they were having an optimum sized high-efficiency unit in the high 70 percent range.

That is why we are urging in our testimony that an efficiency standard be established at some level, about 70 percent.

Mr. LANHAM. Mr. Chairman, I agree with that, because some of our contracts, they will come in and contract for 60 percent of their nameplate rating and they operate at about 70 percent of that which gives you about a 40 to 45 percent output from the facility.

The CHAIRMAN. Mr. Peevey, you stated that the California PUC suspended Standard Offer No. 4 for all California utilities in April 1985, and it temporarily suspended Standard Offer No. 2 in March of this year. What, in your opinion, were the basic reasons for these actions by the California PUC?

Mr. PEEVEY. I think the California Public Utilities Commission came to the conclusion that there was an oversupply of QF facilities in the State of California prospectively, and that they were well in excess of the resource needs of the principal utilities in the State of California.

It happened, the suspension of Standard Offer No. 4, in particular, happened in a couple of ways. The Commission suspended it in northern California in the fall of 1984, and then southern California in the spring of 1985.

What happened is, in the last few weeks prior to its suspension on April 17, we had what was a veritable gold rush of applicants, contracts coming into our offices which were, under the regulations, compelled to sign, which led to this high number of QF's under contract, both for us and for our sister companies in the State of California that, in total, approached 16,000 megawatts.

The CHAIRMAN. Do you think the California PUC reacted too slowly?

Mr. PEEVEY. I think the California PUC was caught in a situation that with the decline in oil prices and some other factors, it could have—well, to put it bluntly, they could have acted faster; yes, sir.

The CHAIRMAN. Thank you.

Senator Evans.

Senator EVANS. Thank you, Mr. Chairman.

First, some general observations. I do not know if they are even in the nature of questions, but let me pose several statements and see if there is general agreement from this panel on them.

First, that the passage of PURPA certainly has generated a whole lot of new power; that if the nature of the act was to encourage the generation of power during a time of high power costs, shortage of petroleum fuels and a question about electric capacity, it certainly has been a success in that respect.

Second, probably most of that power may have been produced at or maybe even somewhat less than the cost of nuclear plants over that period of time—not nuclear plants as they were designed to cost, but as they actually ended up costing.

And, third, that it probably has not had the result of reducing dependence on petroleum-based fuels, as was once thought.

Are all three of those general—is there general agreement that those are sort of the results of PURPA?

Mr. SIMMONS. Senator Evans, I think I would agree with that and I think I would emphasize that, really, the amount of generation we have had, and we have certainly had a lot of it, in particularly in the Texas area and Louisiana gulf coast and California, and I think it has really come about not only because of legislation but primarily because of the drop in natural gas prices.

If you will go back some 4 years in our area, and we had some cogeneration being discussed using some coal and petroleum coke, little of that ever developed, but as soon as gas prices dropped, then we had a whole lot of it come about.

I think most of it, if you will look at the gas prices and you look at the capital costs associated with the gas plants producing, it has been produced at less than nuclear plants.

But I will ask that you look at the cost of nuclear plants and comparable coal-fired plants that are built for some 35 to 40 years and at the levelized cost of those plants rather than looking at the earlier phase-in, when you put the plants into operation. By their very nature, with the new powerplants, depreciated as they go into service, and the first years of operation, the carrying costs are greater than they are in later years.

What you see quoted so often is the first years of operation of nuclear and coal plants compared to cogeneration. What needs to be done is look and see what you would have with those plants over a levelized basis of some 40 years, and then look and see if you can depend on natural gas cogeneration being there—even being available—in some 35 to 40 years, and what that cost might be.

Senator EVANS. I would agree with that. We got deeply into that subject and the need to try to capture not only the levelized cost, but the total cost over a period of time, the generating period of any facility as we did our work throughout the Northwest Power Council.

I think there were other requirements that we are probably not yet capturing fully in terms of, particularly coal and nuclear plants, but probably all plants as well, and that is the identifiable environmental costs. The total costs of shutdown, of storage, of spent fuels, of all of those problems connected with nuclear and of course the potential environmental costs of coal plants, when and if we ever discover the accurate reflection of coal plant production with acid rain.

Let me turn to some specific questions then. Mr. Simmons, you suggested that really change in legislation is not needed; that regulatory changes could handle the problems, but, of course, regulatory changes have not occurred. Would it not be desirable to be more explicit in legislation, try to use the experience of the last 6 or 7 years to reconstruct legislation that will still offer the kind of incentive that probably is desirable in the long run to ensure continued flow of energy supplied at reasonable costs, but to be more explicit in the legislation so that we do not run into these aberrations at whatever whim or decision that is made by FERC, or the regulatory commissions at the State level.

In other words, why not? Is there some concern or some fear about more explicit legislation federally?

Mr. SIMMONS. I think there is also a fear and a problem trying to make explicit legislation. I was simply hopeful that the regulatory approach could work and I think that it very well can and should be given an opportunity to. I think that FERC should, and I think that perhaps that will look into all of these problems associated with cogeneration and take an approach similar to what they have done with the transmission, that they have put in a notice of intent, and do a similar thing with cogeneration. So they can get an identification of these problems and a quantification of it and really bring this up to a summary level. And also put out more detailed information regarding the qualified facilities that we have in the many States.

This simply has not been done and we need more information about those installations and more of the problems pulled together and quantified overall so that the FERC can have an opportunity to revise the regulations to correct these things. If that is not done, then perhaps we will have to have some legislation.

But I am hopeful, and I believe the easier and better way of doing this would be have an approach to change the regulations at the FERC.

Senator EVANS. We have tried that on a number of other occasions and found that only occasionally does FERC respond to our recommendations.

You suggested that FERC set its regulations so that the avoided costs payments do not exceed the cost of constructing the facility. Is that really an appropriate ceiling to be set? Could there be an occasion, or many occasions, where the cost of constructing the facility may be substantially less at a period of time than the avoided costs for the utility to acquire its own generating capacity and that somewhere in between those two might be a good deal for both sides.

In other words, is that too tough a ceiling to be set?

Mr. SIMMONS. Well, I don't think so. And I am talking more specifically about the capacity of avoided costs here. Again, about the fact that the avoided costs, capacity costs in the State of Texas, in particular, and many other areas, is set on the basis of a very high ~~capital costs~~—lignite or coal plant—yet the facility being built is a relatively low cost natural gas plant.

So I think there needs to be some recognition of that difference in cost and to put it into effect so that some of that great savings that is accruing to those cogenerators taking advantage of that difference in cost, some of those savings can be passed onto the ratepayers, rather than going to the industrials.

Senator EVANS. I understand all of that, but what you are suggesting when you say that the cost should be no more than the cost of building that cogeneration plant, you are saying that all of the savings ought to accrue to the ratepayers. It seems to me that there could be a lot of situations where there is a considerable gap between that lignite or another kind of plant that the utility might be pushed to construct, if they are right up against their limits on capacity, and the cost that the cogenerator might produce it for.

I guess I get to something like, I think what Mike Peevey was suggesting, that maybe it is a share of the savings concept that we ought to be considering.

Mr. SIMMONS. I think there will still be some room for savings for the industrials in the energy payments there, rather in the capacity. So I think there would be some room for the cogenerators to still have enough profits and enough encouragement to build these, saving from the energy rather than from the capital costs, carrying costs.

Senator EVANS. One final question, the decisions of FERC and presumably the regulatory commissions to set an avoided cost which, of course, is the guarantee for a PURPA generator, in your view, is there any—should not avoided costs be zero if your utility has a surplus of very, very substantial portions, far more than is needed for reliability purposes; far more than is needed for any legitimate foreseeable future time?

How can FERC or the regulatory commissions legitimately suggest that the avoided cost at that point is, you know, the cost of nuclear or coal generation, when you do not need any power?

Mr. SIMMONS. I think that FERC can and I think that that is envisioned in the regulations of FERC. It has simply been interpreted by the States differently. In the State of Texas, we, the utilities, are not required to make capacity avoided costs, and you must remember that there are two types of avoided costs we are talking about—capacity and energy only.

But in the capacity only payments, the State of Texas and some other States do not require that capacity be bought over and beyond the true generation, plus the load, plus the reserve situation for the plants. That is the way to approach it, yes, sir.

Senator EVANS. The same things apply on the energy side, as well, can they not?

Mr. SIMMONS. I think that the energy side in calculating avoided costs, it is very important that the avoided costs be calculated on the true avoided, the actual avoided costs, and further, that those avoided costs be calculated on an hour-by-hour basis and when you do this, you create the marketplace that determines that in those periods of time when the utilities have very low loads and that their generating costs are low, that their payments to the cogenerators will be low.

I can assure you that we make notices to our cogenerators each day what we anticipated are our payments that night, and those cogenerators are not going to sit there and lose money. That is a greater incentive for the cogenerators to reduce load than any rules that was ever promulgated by the PUC or any tiered rate that is ever put in.

So, I think it is important that those energy-only avoided costs be determined on an hour-by-hour, actual avoided cost determination.

Senator **Evans**. Is that being allowed, or is that the current practice uniformly by utility rate commissions throughout the country, though?

Mr. **Simmons**. That is the practice in Texas and a few other States. It is not generally done, but we think that is the proper interpretation of the FERC legislation and should be more specifically put out in guidelines by FERC to require that in the State——

Senator **Evans**. What would be wrong with that kind of thing being explicitly stated in the statute?

Mr. **Simmons**. I think that if the FERC does not respond in a reasonable period of time, then perhaps it has to be done.

Senator **Evans**. Mr. Lanham, you represent a utility that I presume, like most in the Northwest, is energy constrained rather than capacity restrained. What about this question of avoided costs? What is appropriate for a regulator to set as appropriate cost for a PURPA generator, when you may have an exceptional amount of surplus?

Mr. **Lanham**. Senator Evans, when we requested a reduction in our avoided costs, we established it at our fuel costs which was 15 mils. Now, in all consideration and due respect to the Commission, they did reduce the capacity charge. We do not pay a capacity charge any more. It is just a total energy charge. They sort of combined it because they couldn't perform. They have not been able to perform.

But, nevertheless, until you remove the regulation or the law that says we have to buy the cogeneration—let me give you the option to purchase it from somewhere else—your costs are going to be extremely high.

Senator **Evans**. On pages 12 and 13 of your statement, you had an interesting example of a company's prospectus, apparently a cogenerator or at least someone who expected to sell power to you under PURPA.

The projected is expected to yield a 20-percent cash return to the investor each year for the first 7 years. At the time the debt will be repaid, the investor's cash return is expected to increase to 50 percent a year for up to 28 more years. Investors will benefit from investment tax credits, energy tax credits, the 5-year depreciation. Collectively, these tax benefits will recover 70 percent of the investor's investment the first year and shelter all its cash-flows through the fifth year.

That is a pretty good investment. Normally returns of that magnitude would carry with them a very, very high risk. What is the risk of that generator?

Mr. **Lanham**. In my estimation, there is not too much risk at all, unless they run out of wood.

Senator **Evans**. That is not likely in Idaho, is it?

Mr. LANHAM. Not quite. They have a forest over there that beetles got into and that is what they are harvesting—that and others. As long as it runs, it is a moneymaker.

Senator EVANS. And as long as it runs, you are required to purchase at a fixed price and they will generate that kind of cash and get that kind of return. Is that correct?

Mr. LANHAM. I was required to sign a firm 35-year contract for, in that case, capacity as well as energy.

Senator EVANS. Was that, in your view, at a higher price than you could actually get the same energy someplace else?

Mr. LANHAM. That plant has required us to pay over 11 cents a kilowatt hour for its energy. You can buy it anywhere on the market at far less than that.

Senator EVANS. It is pretty hard to buy anything that expensive, is it not?

OK. Mr. Hebert, you had an interesting end result. Do I understand correctly that what has happened, in your view, is that when the utilities are prevented by the Fuel Use Act from expanding further, or have been over the years, into gas turbines, that the cogenerators then are producing far more than the process heat they need for their own activities, or even electricity for their own activities, just barely meeting the efficiency standards and are, in essence, making an end run around the Fuel Use Act by using natural gas the fuel.

Is that one of the end results of PURPA?

Mr. HEBERT. That is precisely one of the results.

Senator EVANS. Are they then selling to you the end result of that power at what are your true avoided costs, or are you finding that that power is being sold to you at a higher price than you could get power elsewhere; or do you even need the power that they are selling to you?

Mr. HEBERT. No; we are satisfied that, between the States of Texas and Louisiana, where we serve, that we are paying true avoided costs. We have no quarrel with our commissions on the way that they are implementing the avoided costs methodology.

We are not required to pay capacity component of avoided cost as long as we are long on capacity. We had some problems with standby costs, serious problems, where our capacity has been idled by the production of power from cogenerators. That same capacity is required to be supported by remaining ratepayers because these cogenerators in large measure are industrial customers who are leaving the system that was built to supply their load, and so ultimately, the remaining ratepayer will be supporting the system that was built. That will result in higher rates, and we think that rather than having the ratepayer support the system that has been idled, that that cost should be borne by the cogenerator who are causing these problems.

That is a significant problem that is not being addressed in the standby costs.

Senator EVANS. It is not being addressed because the regulators have not chosen to address it? Do you think that that is likely to get the regulators to recognize that, or is that something that may require legislative action to ensure?

Mr. **Hebert**. It may require legislative action. I am hopeful that we can be convincing in both States and hopefully, with the FERC's help, maybe we can get the State commissions to agree that it is a serious problem, or will be a serious problem for our ratepayers.

Senator **Evans**. Mr. Chairman, I just have one or two questions of Mr. Peevey.

Would you like to comment further on your suggestion that perhaps the more appropriate approach to the whole question of cost would be a share of the savings concept?

Mr. **Peevey**. Well, I would just add that you have to look almost technology by technology here. There are situations where avoided costs may be at this point, point A, and way below that, and the true cost of generation of the QF is way, way below and all would be served—the interests of all, perhaps, but the QF—certainly economic efficiency in the Nation would be served, and the protection of scarce resources would be preserved if we could negotiate a price somewhat below avoided costs that would be more in keeping with the true costs of producing electricity by that QF.

We need that flexibility, I think, for all sakes. How that is exactly done and exactly in what formula, I think we should leave to the State commissions to decide. But FERC could be very helpful here in promulgating regulations that would bring that about.

Senator **Evans**. Have you attempted to negotiate any such contracts with any QF's, or have you felt that there is no negotiating ability with the rules setup the way they are?

Mr. **Peevey**. We have negotiated contracts with QF's at below our avoided costs, yes. At some discounted fraction thereof, frankly, seeing that as a benefit to the ratepayers on the Southern California Edison System.

Senator **Evans**. And there has generally been willingness on the part of the power producer to do that?

Mr. **Peevey**. There has not been universal willingness or acceptance of the notion, but sometimes it has come about for various reasons.

Senator **Evans**. You must have exquisitely good negotiating techniques because, am I not right in suggesting that if they choose not to negotiate, they could rely on the avoided costs level and sting you for more money?

Mr. **Peevey**. That is true, but I think that there is also growing—there is an awareness and this hearing is an example of that; that the situation is changing. That the utility has needs for dispatchability and so forth, as well as, in the area of price, that to be bullheaded by all QF's indefinitely is not in their interest, nor in anyone else's interest.

I think that there is some appreciation of that. I hope it grows rapidly as this hearing continues and others in the other body.

Senator **Evans**. I guess to put it bluntly, some are looking at those golden eggs and they are beginning to look more and more like brass?

Mr. **Peevey**. Maybe they are not gold all the way through.

Senator **Evans**. A final question on this whole either sharing the savings or negotiated settlements, do you think that those arrangements can fully withstand court tests, given some of the recent court decisions, particularly the Supreme Court decision in American Paper Institute?

Mr. PEEVEY. Not being a lawyer, I frankly can't answer that question.

Senator EVANS. I am not a lawyer either, so I cannot follow through on it. [General laughter.]

Mr. PEEVEY. I don't know.

Senator EVANS. But together, we could make a much finer arrangement than if all the lawyers got together.

Mr. PEEVEY. I would hope so; certainly the two of us can.

Senator EVANS. OK. Thank you, Mr. Chairman.

The CHAIRMAN. I will not get between two engineers.

Mr. Lanham, you made some reference, and I wonder if others have any experience, as well, with respect to the reliability of the interconnection systems. I recall that you started out climbing poles. The fellow that is up there on the pole working on the line, he wants to know whether it is dead or not.

And, if I recall correctly, in one of the first instances of interconnection with a cogenerator, the device that was supposed to make certain that when the company pulled the switch on the line, the cogenerator went off, too. It did not work.

Mr. LANHAM. No, it didn't.

The CHAIRMAN. Have there been instances of danger to the linemen as a result of the interconnection of the cogenerator's facility?

Mr. LANHAM. Senator, what we did after that accident, and fortunately, we didn't kill or injure anyone, we went in, the company did, and redesigned—we design our own interconnection now—so that in case of a fault, it trips off the line and it does not come on for 5 minutes.

Your load can come back on, and therein lies a problem, also, because the generation didn't come back. But it is a safety problem for our people which we consider more important than some of the other.

The CHAIRMAN. That equipment that you design and install and require for cogeneration; is that a cost to the cogenerator, or is that a cost to the system?

Mr. LANHAM. That is a cost to the cogenerator. He is forced to pay it.

The CHAIRMAN. Do any of the others of you have any comment with respect to the safety of the interconnections?

Mr. PEEVEY. On the point that Mr. Lanham made, I would just add the following. In California right now, there is a piece of legislation through the State Legislature that would ensure various safety standards for individual workers and it happens to be supported by a number of the unions in the State of California, electrical unions, just because of the concerns that you pointed out.

We are supporting that legislation. Our concerns, in addition to the safety ones, are in the system reliability area, because in the West, with our various patrol areas and all, it can be a serious problem when you have hundreds of cogenerators coming on and off the lines, in and out of your system, without the proper controls. That is why dispatch and other matters that I enumerated here today are a real concern that we think FERC could do more on, and hopefully, if FERC can't, then you can.

The CHAIRMAN. Mr. Simmons, do you have reliability problems?

Mr. SIMMONS. Fortunately, we have very few installations on distribution lines. In fact, all of our installations on transmission lines, where you have the ability to use more sophisticated and better control devices and protection than you do on distribution. So our experience, generally, has been good on transmission lines only because you can put more elaborate equipment on it than you can on distribution lines.

The CHAIRMAN. Aside from your company, does the EEI have a position with respect to reliability?

Mr. SIMMONS. I think we all have a concern that where you do apply cogeneration to it, that you do add any necessary transmission lines that are needed so that you maintain the same level of reliability that you would have had if the cogenerators had not been there; yes.

The CHAIRMAN. Gentlemen, thank you very much for your testimony. We appreciate your time and the effort that has gone into not only your appearance here today, but in the preparation of the statements. It has been very useful and helpful. Thank you very much.

The members of the second panel are all in their place, and I appreciate the efficiency with which they did that. I would remind all witnesses, that their entire prepared statements will be placed in the record in full. You will be invited to summarize, if you can do so, in the interest of time.

We will start with Mr. Morris, Cogeneration Coalition of America.

STATEMENT OF ROBERT E. MORRIS, ON BEHALF OF THE COGENERATION COALITION OF AMERICA, INC.

Mr. MORRIS. Thank you, Mr. Chairman. My name is Robert Morris. I am chairman and chief executive officer of Energy Factors. That is a company that owns and operates a number of PURPA-qualifying facilities. And I am appearing today on behalf of Cogeneration Coalition of America, Inc.

I will try to make these remarks brief, in light of your request. I will summarize my salient points in just a minute.

We are submitting for the record both the full statement of the Coalition and my own full statement.

We know that you are being flooded with many arguments for and against the rapidly growing new industry that has been spawned by the Public Utility Regulatory Policies Act. I have read many of those arguments and I have heard a few more today.

I would comment that it seems to me that most of the ones that I heard today are being handled very well, at least in California by the local public utility commission, and I doubt that any legislation that you might try to enact to change that situation might not meet well with the Supreme Court in light of their decision sometime back.

I would also comment that Mr. Peevey is modest. His company has probably more cogeneration under their ownership than any corporation in the United States. They have done an excellent job with it. We are also building a plant in their territory and find them very cooperative to work with.

I must say, however, that each of the people giving testimony today have their own self-interests, and you have heard their biases and you will hear mine. However, what I shall offer has been colored by 18 years as a utility execute, and the last 7 years of that was as chief executive officer of San Diego Gas & Electric Co.

For 15 years of that time, SD&E operated three large cogeneration plants serving the Navy. My new company, Energy Factors, bought those Navy plants and has built and operated three additional industrial cogen plants; has contracts for seven more cogen plants, two in New Jersey, one in Connecticut and the others in California.

In addition, we have contracted for five wood-burning plants that will deliver their entire electrical output to major utilities.

Each of our projects require extended negotiations with the utility. There is no question that without PURPA, there would have been no opportunity to begin negotiation with any utility, regardless of the circumstance.

I would like to say that because of the utility background that I have, I really would like to think of our industry, at least Energy Factors, as working with the utility, not in competition to it. We are attempting to understand their problems and we stand ready to negotiate special contracts with any of them to try to alleviate some of the offpeak problems that they have in particular.

Just to summarize the points that we make in the testimony, I would remind you that we are dealing with monopolies and because they are monopolies they have enormous bargaining power with us as we approach them. They are able to borrow money based on their balance sheets, and if they were permitted under PURPA to own more than 50 percent of a cogeneration plant, they could very quickly extend that monopoly power to the plants that they would propose to build.

I think that the limitation that was placed with PURPA has been beneficial.

We would suggest that the contracts that we enter into are often regarded by lenders as being subject to a change by the local PUC's. We would argue that a contract should be binding on both parties after it is approved by the PUC, for the life of the contract.

To the point of avoided costs. In many instances, we believe that avoided costs are too low; that they do not represent a cost to the consumer; that we are providing capacity to utilities that have abandoned their generating future because they are simply not investing in generation any longer.

There has not been one new major baseload generating plant started in this decade. There are a number of plants that are in the pipeline. All of them seem to be subject to controversy by the local PUC as to whether they should allow that capacity in rate base, but only because they are so tremendously over priced as they built them.

The avoided cost issue for capacity seems to me to be based on a bargain as far as the utility is concerned. In California, it is based on the cost of a peaking plant. The highest cost in the State is about $750 a kilowatt plant, and no utility would attempt to build a coal-fired plant, a nuclear plant or any old baseload plant and hope to get it in for $750 per kilowatt.

I would agree with the testimony of the first panel on the Fuel Use Act. I think that it has outlived its usefullness. I think that so long as a plant meets the efficiency requirements that have been established by PURPA, that any utility or cogenerator should be allowed to be exempt from the Fuel Use Act to the extent that they can use oil or gas.

I would also suggest that we reenforce the standby provisions that were really a cornerstone of PURPA when the regulations were enacted. The Alcon decision has created an enormous amount of confusion. Utilities have been using it as an excuse for refusing to connect to third-party owners for PURPA plants of various kinds, and I do not believe that that was the intent of PURPA.

I would argue that the future for this industry will hold that transmission lines will become common carriers so that those of us who can provide power economically to a utility that needs it cannot be barred by the fact that we have an access to existing transmission line.

We should also try and work to restructuring the utility monopoly that we found for the electric utilities. I see no way that you will ever be able to do away with the distribution monopoly. I wish I could find one, but I don't.

I do think, however, that both generation and transmission eventually should be separated from the monopoly power that exists today.

Thank you.

[The prepared statement of the Cogeneration Coalition of America, Inc. follows:]

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Written Comments of the

COGENERATION COALITION OF AMERICA, INC.

On

IMPLEMENTATION OF PURPA AND DEVELOPMENT OF
COGENERATION AND SMALL POWER PRODUCTION FACILITIES

Before the

SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

June 3, 1986

The Cogeneration Coalition of America, Inc. (Coalition) respectfully submits these written comments to assist the Committee in evaluating the current effectiveness of the Public Utility Regulatory Policies Act of 1978 (PURPA), current approaches to implementation by the Federal Energy Regulatory Commission (FERC) and state public service commissions, and the relationship of these issues to the growth of cogeneration and small power production facilities nationwide.

The Coalition wishes to express its support for the efforts of the Committee and its membership to create a fair, competitive, and equitable market for the development of cogeneration and small power production. We welcome these hearings and the opportunity to address policy implementation goals under PURPA, its relative successes to date, and the need for further implementation of such goals for the future.

I. STATEMENT OF INTEREST AND IDENTIFICATION OF THE COALITION

The Coalition is a non-profit organization comprised of industrial users, gas utilities, equipment manufacturers, project developers and engineering and design firms which support the development of cogeneration resources nationwide. Since 1980, the Coalition has worked to support the removal of unnecessarily restrictive federal and state regulatory barriers to cogeneration development and for the provision of necessary financial and regulatory incentives to encourage project development. The Coalition also has established relationships with other associations and groups supporting full development of national cogeneration potential through such organizations as The PURPA Coalition, Inc.

The current corporate members of the Coalition include: Brooklyn Union Gas Company, Southern Connecticut Gas Company, Industrial Co-Energy Systems, Inc., Independent Energy Corporation, Michigan Consolidated Gas Company, Thermo Electron Corporation, Enegrid Investment, Ltd., GKCO, Inc., HYDRA-CO Enterprises, Inc., Dow Chemical Company, Management Analysis Company, Energy Factors, Elizabethtown Gas Company, Cogenco International, Inc., Kaiser Power Company, The Babcock & Wilcox Company, Cogeneration Technologies, Inc., Central Hudson Cogeneration Development Company, and Electro Thermal Systems, Inc. Our members currently operate cogeneration and small power production facilities in many locations, and are engaged in the development of cogeneration or small power production projects in most states in the country.

II. BACKGROUND: DEVELOPMENT OF THE COGENERATION INDUSTRY

A. Origins of Cogeneration

As the Committee is well aware, cogeneration, which is defined as the sequential generation of electrical or mechanical power and useful thermal energy (such as heating or cooling) from the same primary energy source, is not a new concept (Attachment 1). Cogeneration started in Europe and was introduced in this country in the late 1880's. At the turn of the century, cogeneration and dispersed power generation supplied over 50% of the power produced in the United States. The growth of electric utility networks, related economies of scale and cheaper fossil fuels, however, resulted in the decline of cogeneration. By 1970, cogeneration accounted for less than 4% of the total electricity produced in the United States.

B. Federal Incentives Led to Market Growth

After the Arab oil embargo of 1973-74, conservation and other alternate energy options began to be evaluated as means of providing this nation with energy independence. Cogeneration resurfaced as a viable method of meeting industrial and commercial energy requirements and as an alternative to spiraling energy costs. The enactment of PURPA in 1978 was the catalyst providing for the resurgence of cogeneration. Through PURPA, Congress intended to encourage industrial and commercial cogeneration by prohibiting electric utility rate discrimination against, and providing rate benefits to, qualifying cogeneration and small power production facilities (QF's), as well as providing them with the right to interconnect to the electric utility grid. PURPA also exempted QF's that sell power to electric utilities from rate regulation under the Federal Power Act (FPA), from financial regulation under the Public Utility Holding Company Act (PUHCA), and from certain elements of state public utility regulation. Other related provisions of the National Energy Act (NEA), enacted in 1978, provided exemptions or related regulatory relief from provisions of the Natural Gas Policy Act, and the Powerplant and Industrial Fuel Use Act.

Today, certain federal policies and energy programs promote the use of some very costly technologies and resources, at the expense of considerably cheaper energy efficiency alternatives, such as cogeneration. Continuation of such policies, while politically attractive, fails to reflect the current needs in the energy marketplace. See, C. Schneider, "Least-Cost Utility Planning: Providing a Competitive Edge," Public Utilities Fortnightly, April 17, 1986, p. 15ff. In contrast, PURPA, which has proven to be the most effective component of the NEA, reflects truly sound energy policy. Its success has been widely recognized at state and local levels and nationally. The support it provides to new and efficient technologies such as cogeneration has evoked both the respect and growing market concerns of electric utilities nationwide.

With escalating world oil prices and the enactment of legislation such as PURPA, energy efficiency methods including cogeneration have become viable long-term tools for industrial, commercial and utility planning. Energy efficiency, including cogeneration, now provides up to one-fifth of U.S. energy services. Id. The total value of energy efficiency increases in all sectors of the economy has reached $150 billion per year. Id. [1/] Incremental, more capital-intensive energy efficiency investments could reduce our current $500 billion a year energy bill by an additional $150 billion. Id.; for further details see also, "Federal R&D on Energy Efficiency: A $50 Billion Contribution to the U.S. Economy," American Council for an Energy Efficient Economy (Washington, D.C.), March, 1986. Furthermore, cogeneration and small power production helped undermine OPEC, to the point that, reportedly, OPEC's effort to stabilize current world oil prices is in part a response to growing pressures from world energy efficiency improvements.

C. Cogeneration Potential is Virtually Untapped

There is general agreement that the full potential for the development of cogeneration has not yet been tapped. This technology is poised to embark in this decade on a major growth

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[1/] PURPA and its related results have been cost effective in that energy efficiency's share of current federal energy subsidies (almost $40 to $50 billion per year in appropriations, guarantees, and tax subsidies) is less than 1%. This cost effectiveness is the result of privatization and reliance on the entrepreneurial capabilities of U.S. industry.

pattern, which could be accelerated by sound, consistent energy policies and improved economics from stable federal tax policies. American industry has recognized that its future success and ability to compete worldwide remains tied to controlling energy costs and assuring the reliability of energy supplies. State and federal policymakers are also recognizing that promotion of cogeneration can yield increased energy efficiency and facilitate demand-side load management. Cogeneration offers an opportunity to better match individual energy systems with customers' load requirements, which is typical of energy load management objectives in utility planning for the future.

These observations were confirmed by the President's Commission on Industrial Competitiveness in a 1985 report which recognized that "the United States is losing its ability to compete in world markets . . . a trend that, if not reversed, will lead to a lower standard of living and fewer opportunities for all Americans." Global Competition: The New Reality, President's Commission on Industrial Competitiveness, Vol. I (Washington, D.C.), January, 1985, p. 11. For example, more than one million workers in companies having at least 100 employees lost their jobs in 1983 and 1984 because of permanent work force reductions or because their companies went out of business. Almost two-thirds of the job losses were concentrated among larger firms in the manufacturing sector, and most were caused by increased competition or reduced demand, according to the General Accounting Office. For many industrial firms, better control of energy costs could lead to an improved ability to compete. Cogeneration may be one of the most effective planning tools by which heavy manufacturing industries nationwide can compete with growing competition from abroad.

The basic strategic concerns of industrial companies include the predictability of future fuels and feedstock supply and pricing, and the continuing need for reliable electric power at a predictable cost. Historically, the fuel and energy cost component of finished or semi-finished products has been 2% to 3% of the final cost of production. Now, this cost component has reached 13% and is still growing. Obviously, such production cost growth drastically erodes profitability. See, R. H. Quig, "Process Steam and Cogeneration--A Diversified Market Opportunity for Electric Utilities." Paper presented at EEI Annual Executive Conference, Hilton Head, South Carolina, September 27-29, 1982. As a result, industrial planners currently rank fuels, energy and related environmental matters as equivalent in significance to:

1. International competition;
2. Raw material sources and cost;
3. Labor and its productivity;
4. Plant modernization;
5. Market and competitive pricing; and
6. Cost of capital.

The nation cannot afford to rest on the recent collapse of world oil prices, and to wish that the need for energy efficiency and cost containment would go away. Oil fuel prices represented only 2.7% of the retail price of electricity in 1985. As illustrated on Attachment 2, non-fuel expenses, mainly capital, constitute 75% of today's retail price of electricity. Even if the utilities' oil costs dropped by 50%, the average retail price per kilowatt hour (kwh) would decline by only 0.1¢.

These savings are insignificant when compared to the rate shock caused by newly completed nuclear powerplants, which have life-cycle power costs of two to four times today's national average electricity price. Schneider, p. 16; see also Attachment 3. Even under best case assumptions, the nuclear plants under construction will cost a total of $191 billion more than the fuels they will displace over their lifetime. Nogie & Alan, "Rate Shock: Confronting the Cost of Nuclear Power," Environmental Action Foundation (Washington, D.C.), October, 1984. It is therefore likely that energy efficiency, including cogeneration, will continue to provide a viable alternative means of achieving energy independence and security.

The greatest potential for cogeneration has traditionally been represented by five major sectors of the economy: food, pulp and paper, chemicals, petroleum refining and primary metals. But, increasingly, these industries are being joined by schools, colleges and universities, banks, restaurants, hotels, hospitals, and other institutions, as well as municipal resource recovery plants, which also offer the opportunity to solve our solid waste disposal problems for the future. Cost controls and momentum for cost containment are generating new pressures to pursue cogeneration projects in commercial applications, which may be an area of substantial market growth in the 1990's.

Various estimates indicate that technical cogeneration market potential could equal up to 40,000 megawatts (MW) of new power by the year 2000. Actual penetration will vary, dependent upon the maintenance of a stable development environment under PURPA, the implementation of necessary state laws, and the federal tax policy by which financing of such projects must occur. The best available estimates suggest that the cogeneration market currently represents 7% of the total electricity produced in the U.S. It is predicted that this market will increase to over 10% by 1989, and 15% by 1995, with varied levels of penetration by region and by industry (Attachment 4).

The market already has become increasingly competitive. Between 1980 and 1985, almost 4,000 MW of cogeneration and small power capacity were actually installed. During 1984-85, approximately 6,000 MW of cogeneration and small power production facilities were in some stage of development, such as procurement or construction. During 1985 alone, according to General Electric (GE), nearly 3,000 MW of cogeneration were booked as plant orders for the year. J. H. Williams, "Projections for the Overall Market: The Coming Shakeout." Paper presented at McGraw Hill Seminar on The Cogeneration Market: Opportunities Over the Next Three Years, April 8-9, 1986.

Much of the current cogeneration activity has been in high growth areas, notably California and Texas. Cogeneration development is also spreading to areas with high fuel costs, such as New Jersey, Florida and the Northeast, and areas with escalating electricity costs, such as Michigan, Kansas and Oklahoma. In fact, there are significant new cogeneration plants proposed or under development in nearly every major area of the country.

D. Many U.S. Regions Will Benefit from the Development of the Cogeneration Industry

In addition to the fundamental benefits of cogeneration, which will be described in some detail in later sections, there are a variety of local and regional benefits associated with the development of cogeneration and small power production projects which are frequently overlooked. For example, in New England, all purchased power from cogeneration or alternative energy producers directly offsets foreign oil, natural gas, coal or Canadian electricity imports to the region. In the case of oil displacements, there is a direct savings to this region, and the nation, even at lower prices, which has been estimated to be as much as 4¢ per kwh, for all such power produced. R. P. Kennel, "Independent Power Production When 'Coals Ought to Be Carried to Newcastle.'" Paper presented to Electric Council of New England 1986 Annual Conference, January 30, 1986.

Furthermore, the economies of many states are enhanced by the growth of the cogeneration industry. Suppliers and consumers benefit in four critical ways:

1. Energy and cost savings from cogeneration cause industry to be more economical in supplying goods and services to consumers and competitive in the world marketplace;
2. Cogeneration can protect employment and related purchasing power in regions where it helps to

maintain the viability of the industrial and commercial sectors;

3. Cogeneration developers purchase equipment and services from suppliers in many states across the country; and

4. Vendors in numerous states are called upon to meet operating, maintenance and fuel needs.

Moreover, indirect benefits, such as secondary employment increases, can more than double the economic benefit for various equipment and fuel supplier states.

Cogeneration facilities often require major capital investments in many types of specialized equipment produced across the country. A typical facility could require as much as $25 million of gas and steam turbines, heat recovery or coal boilers, electric generators, and other types of custom equipment. The services of engineering, construction and financial firms would also be needed. Attachment 5 highlights these requirements, in terms of individual cogeneration equipment or development service expenditures, and shows many of the typical supplier states. The geographic diversity of the supplier states clearly demonstrates the significance of cogeneration facility purchases to many regions of the nation. 2/ It has been estimated that currently over one-half of the Fortune 500 companies are cogenerating, or are engaged in the provision of equipment or services to the cogeneration industry.

2/ These important equipment supplier benefits are reviewed from a national perspective in Cogeneration Equipment and Services Market in the U.S., Frost & Sullivan, Inc. (New York, NY), Spring, 1983.

In evaluating the impact of the growth of the cogeneration industry, the Coalition, as an example, analyzed the potential impact of the achievement of 25% of the total cogeneration potential which has been identified by the Department of Energy (DOE) for the Ohio Valley. We projected that this rate of development within the States of Kentucky, Ohio, Pennsylvania, West Virginia and New York would yield purchases of $1,605 million for coal/biomass cogeneration systems; $670 million for gas-driven combustion turbine systems at industrial facilities; and $215 million for packaged cogeneration systems at hospitals, educational institutions and commercial establishments. [3] The analysis also indicated that developers would purchase equipment and supplies from suppliers in as many as thirty states across the country.

In our five-state analysis, direct payrolls for construction alone would total over $350 million for achievement of 25% of the area's cogeneration potential. [4] In another example, for several projects in Maine totalling $100 million, an average of 300 jobs, filled by 95% local labor, will be required during 1986 for completing project construction. Local revenue taxes are likely to be generated at the rate of $500,000 per year for each project.

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[3] These dollar estimates are based on detailed cost and engineering assessments of various cogeneration projects in this five-state area. The cogeneration market potential estimated by DOE was converted into equipment purchases using detailed site-specific cost estimates and vendor quotations for actual cogeneration projects in this area.

[4] This still excludes secondary benefits which could be derived by a U.S. Department of Commerce economic impact multiplier of 1.6.

It should be further noted that, once the initial construction of the nation's cogeneration facilities is underway, their ongoing operation will require the purchase of supplies and services from numerous states across the nation. Moreover, this demand will continue over the life of the facility--typically a span of ten to twenty or more years (Attachment 6). [5] And, once they are operating, the projects will make continuing significant contributions to the local economy.

Over the longer term, projects of 10 MW or less are expected to show growth representing a $2 billion a year market by 1990. A 15,000 MW increase in installed capacity of industrial cogeneration systems between now and 1995 will create a market for cogeneration equipment suppliers, installers and related engineering services ranging from $13 billion to $19 billion (See, e.g. Attachment 5).

Furthermore, many cogeneration projects are joint ventures involving non-recourse project financing, which normally require core agreements, such as a thermal sales agreement, with terms of at least 10-15 years to support the underlying financing. Such long-term commitments promote job stability, retain existing jobs, maintain U.S. business opportunities in heavy industries, and enhance the local tax base.

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[5] These cogeneration equipment supplier benefits were based on detailed cost estimates, manning tables, vendor quotations and other assessments for customer-specific potential cogeneration projects. For example, local jobs to operate and maintain a typical coal-fired cogeneration plant are 2.36 employees per MW; for a mid-sized gas turbine project, 0.24 employees per MW. Operating costs and related supplier purchases are based on manufactuer quotations, outside maintenance service estimates, and engineering consultant studies.

III. THE FUNDAMENTAL BENEFITS FROM COGENERATION DEVELOPMENT

The cogeneration industry is an American industry. As discussed above, this industry uses largely American equipment, materials, services and labor. This industry keeps American dollars at work at home, rather than in use for imports of foreign oil, Canadian gas or electricity, or exotic technologies such as wind or solar (which more often are manufactured abroad). This industry keeps jobs in America, and particularly in those regions of greatest need. It keeps our hospitals' costs down, facilitates service of the health needs of many, and contributes to reducing costs at colleges and universities. Through resource recovery cogeneration, the industry helps assure our military bases of energy self-sufficiency at reasonable costs, and, at the same time, contributes to the solution of our national waste disposal problem. It generates new federal, state and local tax revenues, and solves--rather than creates--environmental problems.

In evaluating the contributions of congeneration--like the help it provides in making U.S. industry more competitive, the obvious benefit of conserving our national resources, and the significant economic impact associated with the development of the cogeneration industry--it is important to focus on the fundamental benefit which the technology offers. Cogeneration is poised to move into the second, mature phase of its evolution and to make a significant contribution toward meeting the nation's need for reliable, cost-effective electricity, in the immediate future and the decades to come.

A. Integration of Cogeneration as a Source of Energy Supply

Cogeneration can provide a ready answer to the financial, regulatory and environmental barriers confronting nuclear power and, increasingly, large coal-fired plants. Cogeneration systems can be installed in small increments, often can be brought on line within 18 to 24 months, and are relatively manageable from a financing perspective. They also offer better risk management benefits to ratepayers, because costs of construction are borne by the developer, and because the owner is generally paid only when its plant is actually generating electricity.

Construction of cogeneration systems adds small increments of electrical supply to the nation's total electricity capacity. This makes it a more effective answer to the problem of short-term fluctuations in demand for electricity than the overbuilding of large-scale power plants. Cogeneration systems offer diversity and flexibility. They provide thermal energy for a range of needs at industrial, commercial, and rural sites, while supplying significant amounts of electricity to the nation's power system.

Because cogeneration represents dispersed power generation, compared to large central powerplants, it is helping to pave the way for the commercialization of new technologies, such as the fuel cell, within the next ten years. Moreover, cogeneration technology is available now: boilers, turbines, generators, and waste heat recovery methods have been available for decades. Many of the engineering/design, construction and equipment manufacturers of the equipment are the same companies that the electric utility industry worked with in the 1960's and 1970's to satisfy growing electricity needs.

The electric utility industry has been giving very mixed signals about the necessity for cogenerated power. Some utilities claim that they are in "excess capacity" conditions, and indicate that they do not need cogeneration. Others indicate that power from such sources is desirable, and that they are relying upon it and are reflecting dispersed power in their operational planning. In any event, there are many indications that the future will demonstrate a need for the power which cogeneration can make available. Hearings were held less than a year ago by this Committee at which electric utility and DOE witnesses indicated a need for power in some regions now, and reflected concern over "when the lights will go out" in the coming decade.

Despite the confusing "excess capacity" argument often raised in discussions of PURPA, many experts have expressed little doubt that new capacity is needed for the 1990's and beyond. New capacity is indeed needed to support continued growth in the economy, to provide for retirements of aging generating plants, and to reduce dependence on high cost oil and gas, especially imported fuel oil. J. L. Beard, "Future Shock: The Coming Electrical Shortage," Constructor, November, 1985, p. 20ff.

The North American Electric Reliability Council (NERC) is projecting growth in kilowatt hour requirements of 2.4% per year from 1985 to 1994. Over the same period, capacity additions are scheduled to average 1.65% per year or less. Id. (Attachment 7)

In 1985, the total available generating capacity was in the range of 600 gigawatts, or 600 billion watts. Of that total capacity, average demand was approximately 450 gigawatts, or 74%. However, of that 26% balance, called the "operating margin," only 3% was actually available for future load growth; 6% was required to satisfy peak loads; and 17% was needed for maintenance and power outages. Id.

Operating margins are recognized as critical for our electric utility system. Moreover, while much discussion has been recently focused on the excess capacity issue, precious little analysis has focused on the quality of such excess, as opposed to its quantity. Given the need for reasonable operating margins and the availability history for large powerplants, the quality of such capacity must be better inventoried and understood.

Generally, our national average capacity factors for electric generating units by type have been declining for ten years (Attachment 8). This is particularly significant when we consider that the demand for electricity represented 26% of all

U.S. energy use in 1972; it represents 35% today; and is projected to rise to 40% by the 1990's.

Concern is also being expressed with regard to the ability of supply to meet this growing demand. The market for new generation projects by electric utilities to meet electricity demand in the mid-1990's has changed because of the following factors, which affect electric utilities as well as cogenerators and small power producers:

1. Forecasting generation in electric demand is highly uncertain.
2. Excessive lead times for new capacity may actually exceed the periods for which electric demand can be predicted with any degree of certainty.
3. For a variety of reasons, the costs of new central generation, capacity and transmission facilities are rapidly escalating.
4. State utility commissions have become increasingly willing to expose electric utilities to the financial consequences of supply and demand imbalances.
5. In the current marketplace there exist supply and price distortions which users, consumers and electric utilities have not effectively resolved. Customers are now seeking to improve their competitive positions by self-help measures and by seeking access to cheaper power.
6. Current distortions in price and supply have not been reduced by the recent growth rate, low inflation and lower interest rates.
7. Risk minimization strategies by electric utilities will be rewarded by state public service commissions, Wall Street, and investors.

Furthermore, analysts are warning of trouble ahead if additional capacity is not designed and placed in construction within three to five years. The electric utility industry's own U.S. Committee for Energy Awareness recently forecast a need to turn to presently idled, oil-fired capacity, causing sharply higher imports from OPEC in the 1990's. S. Marcy, "Study Says Electricity Use Rise May Bolster OPEC," Oil Daily, March 19, 1986, p. 1. This electric industry study projects that if present construction programs for new capacity are completed within six to eight years and electricity use grows at the rate of 3.5% per year, the U.S. will be burning an additional 1.7 million barrels of oil per day in 1994 to generate electricity. This projection also presumes a 60% increase in gas-fired generation. If electricity use grows 4% per year, oil-fired generation will increase by 2.7 million barrels per day. Less than two months ago the electric industry claimed that it cannot handle such load growth, and that it will be forced to place its presently idled 75,000 MW of oil-fired capacity back into service and to construct additional peak-load turbines of 50 MW to 75 MW each. Id.

These predictions are being made at the same time that state commissions are seeking to re-regulate alternative energy development and shift development risks to QF's, away from utilities engaged in their own pursuit of risk minimization strategies. In some states, consumers or ratepayers are seeking to shift all development risks and operating risks to the private power producer, and, in some cases, properly so. The problem is that the normal reward for assumption of such risks by the QF developer is limited or constrained by a regulated monopoly and cost-of-service mentality on the part of the state commissions in setting the rates and contract terms for the power. The Coalition has observed a significant shift in this direction in the last two years.

In the midst of a changing marketplace, cogenerators, like other U.S. businesses, also have been subjected to four fundamentally different tax regimes in the past five years. It is difficult to make clear and rational investment decisions in such an unsettled climate. Recent results are starting to show that this instability is taking its toll. For example, we have seen only a 50% success rate on all QF applications before the FERC, a decline in project financings during 1986, and an almost 10% decline in cogeneration equipment bookings for 1986.

In short, cogeneration offers the flexibility to assist the nation in meeting its need for assured sources of electricity. In the midst of some protests, it is clear that cogeneration is needed, and that it is in the national interest to assure more effective integration of cogeneration and small power production into federal and state capacity planning. However, the cogeneration and alternative energy industry--in many instances like the electric utilities--is facing a constant shift in market signals, new rules of the game, and instability in the regulatory, tax and project financing environments for the future.

B. Efficiency Improvement in Generating Electricity

Despite the problems it faces, cogeneration is rapidly taking its place in efficiency and production efforts across the country, ~~and~~ is being incorporated into public utility capacity and rate planning. This is based in part on the fact that cogeneration systems, which produce electricity and thermal energy in one sequential process, offer substantial savings in fuel use, relative to conventional technologies that separately produce these two forms of energy.

A cogeneration facility needs more fuel to produce both electric and thermal energy than is required to produce either form of energy alone. But, the total amount of fuel needed to produce both electric and thermal energy from a cogeneration system is less than the total amount of fuel needed to produce the same output of electrical and thermal power from conventional technologies. For example, 2-1/2 barrels of oil, or an equivalent fuel, used in a cogeneration system will produce the same amount of electricity and thermal energy as conventional systems will produce using 3-1/4 barrels.

The efficiency levels for converting fuel to energy are much greater in cogeneration systems than in the traditional segregated systems. In a typical conventional system, the industrial or commercial user produces steam from an on-site boiler and simultaneously purchases electricity from a local utility. The overall efficiency for converting fuel to energy in this segregated system is substantially less than 50%, with the remaining 50% being discharged as waste heat. Through the addition of a cogeneration system, the efficiency level increases to between 60% and 85%. The result is not only production of enough steam and electricity to meet the user's requirements, but also, in many cases, production of excess electricity that can be sold to the utility or made available for demand growth at the plant site.

Because of the savings they make possible, cogeneration systems typically can lower the cost of electrical and thermal energy by 25-30%, even after the cost of equipment, maintenance, and other expenses are included (_see_, _e.g._ Attachment 9). Energy fuel cost reductions achieved by displaced electricity currently can result in an average pay-back period of two to five years, depending on the type of fuel used. However, if pending tax reform provisions are enacted by the Congress, including repeal of the investment tax credit and longer depreciation periods for cogeneration equipment, this pay-back could extend to a period of up to ten years.

C. Economic and Market Considerations Independently Support Cogeneration

Sound economics--and not just benefits made available by PURPA--encourage the development of cogeneration as a viable alternative to escalating electric costs. Smaller electric generating facilities mean lower financing costs, simpler construction and lower overall costs to the consumer. A typical cogeneration unit today costs $700 to $1,800 per kilowatt of electric capacity--less than half the cost of new coal or nuclear plant capacity. New technology and packaging of existing equipment is also expanding the market and economic attractiveness of cogeneration. This compares favorably with the recent round of new baseload powerplant additions, which will more than double the existing utility rate base nationwide by 1989, causing a corresponding increase in utility revenue requirements, while increasing capacity by only 12%.

Over a dozen companies have developed modular or packaged cogeneration systems. Instead of being assembled on site by engineers and contractors, the standardized packaged units are factory-built and arrive on skids. This has meant that cogeneration units of less than 1,000 kilowatts can be installed at a reasonable cost. Cogeneration Technical Services, Inc., Factory Assembled Packaged Cogeneration Systems: A Comparative Assessment (Washington, D.C.), May, 1986. Sales of these packaged systems have jumped from fewer than five throughout the nation in 1983, to 30 in 1984, and an estimated 100 in 1985, according to DOE. Sales of up to 40,000 such systems are possible by the end of the century, including 9,000 in hospitals and nursing homes, 1,000 in car dealerships, 5,000 in apartments, 4,000 in stores, restaurants and offices, and 2,500 in farms. In fact, small packaged systems are likely to provide 15% of all cogenerated electricity produced by 1995. See, Mueller & Associates, "Market Potential for Small Scale (15 KW to 500 KW) Cogeneration Systems," November 27, 1985.

IV. NEED FOR A STABLE LEGISLATIVE AND REGULATORY ENVIRONMENT

The decision to deploy cogeneration is predicated, in large measure, on economic factors, the availability of financing, and the federal and state regulatory environment. Each of these categories has improved dramatically in the past few years in several critical respects. On the economic side, the most important factors are the regional price of electricity, the amortized cost of the equipment, the price of the fuel input, and, to a lesser degree, the usage and size of the plant. With respect to financing, financial institutions now understand the technology, can manage the risks, and are comfortable with these project returns. On the regulatory side, recent federal and state laws and regulations have recognized the need to provide stable economic incentives to cogeneration in certain jurisdictions. However, substantial changes in any one of these categories could have a significant impact on the development of cogeneration to its full potential.

And as we have already noted, there are a variety of recent developments which are likely to affect cogeneration development. For example, the tax reform package recently approved by the Senate Finance Committee would make major changes to the tax treatment of the cogeneration industry. The proposal would modify critical incentives for capital investment which are of importance to the financing of cogeneration projects, and, in particular, would repeal the 10% investment tax credit. Of special concern is that, despite the general decision to maintain the ACRS system, and even improve depreciation treatment of many industrial categories, the Finance Committee proposal would result in significantly less favorable depreciation treatment of cogeneration facilities than exists under current law. Members of the cogeneration industry are concerned that the pending depreciation proposal could make cogeneration investments less attractive when compared with investments in other types of assets. Because the cogeneration industry is generally highly capital-intensive, the burden of major shifts in tax policy often fall upon it particularly heavily.

Maintenance of stable PURPA and other federal policies, and balanced state policies, can operate to counterweigh such adverse developments affecting project financing for the future. Moreover, the industry remains confident that once the parameters of the current tax reform debate become clearer, financing of cogeneration projects will continue in 1987, although financing mechanisms may shift. For example, there is likely to be more reliance placed on conventional financing, with less use of non-recourse, private project or third-party financing. Additionally, we may see more use of common stock issuances as a means of financing through public companies, as well as other securities issuances, such as certificates of participation or convertible debentures, for participation in specific projects.

Electric utilities, through subsidiaries or affiliates, may also become a new source of capital, with different investment needs and criteria than traditional lenders have exhibited. Where applicable, bond financing is likely to become an attractive source for solid waste, hazardous waste and district heating cogeneration facilities. Bond financing will provide one-time, up-front capital, avoiding the need to arrange both construction and permanent debt for the facility.

With regard to regulatory developments and incentives, it was not until recently that favorable rates for cogeneration were established by electric utilities and certain state commissions in states other than California and Texas. In the future on the state level, there needs to be created a more favorable, balanced environment for the development of cogeneration projects. This could be achieved through the establishment of rates that include not only the avoided cost of fuel but also, where appropriate, the avoided cost of adding new capacity. The utilization of long-term contracts and standard offers are other devices which, if properly developed and employed, could also benefit the industry, utilities and their ratepayers. Electric utilities also need to be assured that they will be allowed to recover the costs of purchasing electricity from cogeneration facilities through their fuel adjustment clauses, or some other appropriate provision, over the contract term. These, and related suggestions for creating a more stable regulatory environment, are discussed below.

On the other hand, recent efforts to impose burdensome state regulation upon QF's are likely to negatively affect the development of the industry, and also should be addressed. These efforts are contrary to the federal policy, encompassed in PURPA, that burdensome, utility-type regulation of QF's is neither necessary nor appropriate if the cogeneration and small power production industry is to evolve.

With the inducement of a favorable, more stable rate and regulatory environment, the cogeneration and small power production industry has the opportunity to flourish for the future and to provide the significant power contributions which it is capable of offering into the 1990's.

V. GENERAL PURPA IMPLEMENTATION AND ELECTRIC POLICY ISSUES

The Coalition believes that the Committee's request for comments offers the industry, and other interested persons, a significant opportunity to help shape the future of cogeneration and small power production development. Discussed briefly below are some key issues which are likely to affect such development and, therefore, may deserve further analysis and evaluation by the Committee.

While pointing to these issues as worthy of Senate oversight, however, the Coalition strongly emphasizes that no substantial evidence has been offered that PURPA is not effectively working, or that further legislation is needed. Even the recent DOE study on PURPA implementation falls short of recommending the need for legislative action by the Congress at this time. Pfeffer, Lindsay & Associates, Emerging Policy Issues in PURPA Implementation, prepared for U.S. Department of Energy, March, 1986 (hereinafter the "Pfeffer, Lindsay Study").

The Coalition also notes that, while PURPA has been in effect for nearly eight years, the amount of actual experience thereunder is significantly less. This is due to the lead time that was necessary between passage of the Act and its implementation by the FERC, and state regulatory authorities, with a few notable exceptions, such as California and Texas. 6/ Moreover, since its enactment and implementation, PURPA has been subject to significant judicial challenges which only recently have been favorably resolved. Thus, it may not yet be clear how to evaluate PURPA because there has not been enough time to validly measure its impacts.

As was properly recognized by the Pfeffer, Lindsay Study, when dealing with complex legislation, regulations and their implementation, anomalies and the need for corrective regulatory measures may arise. This is reflected in the fact that certain state actions which yielded relatively high avoided

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6/ The Coalition notes in this regard that the California and Texas experiences may be inappropriate benchmarks for evaluation of other jurisdictions. For instance, in California, there was such an enormous differential between the cost of electricity and the cost of fuel during the early development of standard contract offers that any project which minimally met the FERC efficiency standards could generate attractive revenues. Although the circumstances in Texas were quite different, that state may be similarly inappropriate for use as a benchmark. The very large projects in Texas were generally pursued because certain key industries had an enormous appetite for steam, with a smaller demand for electricity. In order, to satisfy the steam load, a large amount of electric generating capacity could be put into place, with electricity sold off to electric utilities. In such projects, the thermal efficiencies are relatively close to the optimum efficiency of the system. These industry characteristics, however, are unlike those found in most other areas of the country.

cost payments have been largely self-corrected, or are in the process of re-evaluation. The Coalition notes that states supporting higher than full avoided cost rates have relied solely upon indigenous state statutory authority. Under the delicate federal and state balance regarding ratemaking matters, states should be permitted to continue to have this prerogative.

Another issue of concern to the Coalition is the current FERC enforcement policy, or lack thereof, with regard to PURPA matters within its jurisdiction. The FERC has effectively abandoned its critical oversight function and enforcement responsibilities, to the detriment of the cogeneration industry. We urge that the relevant recommendations in the Pfeffer, Lindsay Study be supported by the Committee.

Certain issues before the FERC regarding the ongoing implementation of PURPA and relating to the development of new technologies, fuel choices by QF's, and operating and efficiency standards for cogeneration facilities are also creating uncertainty within the industry and should be re-evaluated by the FERC on a generic basis. For example, the FERC recently issued a series of somewhat contradictory orders comprising a body of QF law which is becoming convoluted, confused and unreliable. Furthermore, new filing requirements are being sought by the FERC with no statutory or regulatory authority. If there are problems with the various standards set by the FERC, they should be analyzed, commented upon and corrected by the FERC through a notice of inquiry, policy guidelines or even a rulemaking.

The Coalition also notes that fuel choice and "PURPA machine" issues are being effectively handled in the marketplace through the laws of supply, demand and price. This keeps the federal government out of energy decisionmaking regarding fuel selection and is consistent with the current National Energy Plan. Neither PURPA nor its implementing rules and regulations should be transformed into a program to favor one fuel over another, while electric utilities enjoy unbridled access to all fuel sources. Furthermore, consistent with this policy, the Coalition urges that all current limitations on fossil fuel use for small power production facilities be suspended for at least the next five years.

Also, national data collection functions have been deficient, perhaps as the result of cost-cutting by the federal government since 1981. We also urge that the pertinent recommendations to the FERC and the Energy Information Administration contained in the Pfeffer, Lindsay Study be supported by the Committee.

Finally, we wish to note here our view that, for all of its effort to review in an objective fashion some of these issues and the current state of PURPA implementation, the Pfeffer, Lindsay Study is incomplete and does not present a truly balanced perspective. (A separate critique of this study, prepared for the Coalition, is provided as Attachment 10.) For example, the study fails to discuss those electric utilities that have not devised rates based upon full avoided costs; it ignores the propensity of some electric utilities to litigate PURPA issues at ratepayer expense, as shown by over fifteen lawsuits nationwide; its concern for security requirements in purchase power agreements, which cannot be secured under current insurance or financial services, is not balanced; it ignores the quality of excess capacity and the need for operating margins in its rate analysis; and, without justification, it suggests the imposition of capacity factor requirements in QF power power purchase contracts which the electric utility industry is not capable of achieving.

It appears that the authors have failed to examine consumer equity issues related to baseload powerplant construction like CWIP, AFUDC, tax normalization, amortization of plant costs for facilities not built, and decommissioning costs. Similarly, in its evaluation of QF power and related subsidies, the study provides no balanced analysis of current federal electric utility subsidies of over $20 billion.

The Pfeffer, Lindsay Study also lends unwarranted credibility to the alleged risk of non-performance by QF's because of shifts in world oil or gas prices and supplies, shifts in product lines, etc. This position has been advanced by electric utilities in some instances as support for exorbitant security provisions and other non-price terms and conditions in contract negotiations. Purchase from QF's have also been presented by the utility industry as unreliable, or illusory, based on the concern that the power will not be there when the electric utility needs it.

In reality, the risk of non-performance may be less with QF's than with conventional powerplants. The recent delays with mounting cost escalations or failures like Diablo Canyon, Midland, Zimmer, Limerick, and Shoreham vividly confirm that reality. Moreover, the risk that QF's will not perform is no different qualitatively from the risk that customers will shift to different consumption patterns, or that the relative costs of different supplies will change, or that predictions of corporate models may prove wrong.

The more fundamental issue is: who should bear the risk of uncertainty? The answer is that the utilities should share this risk with the QF developer. But QF's must rely upon the utility's expertise in forecasting its future needs--including its review of alternative forms of available supply--and we must rely upon utilities to establish the most cost-effective program of investment to satisfy those needs, subject to the outcome of state regulatory review. This responsibility has not shifted because of the advent of cogeneration and small power production; the necessary judgments are still very similar.

As a result, the Coalition submits that, if anything, the Pfeffer, Lindsay Study should be seen as an indication that, while not perfect, PURPA is fundamentally working. If fine tuning is required, it may need to occur before the FERC, and the state public service commissions, rather than through Congressional action.

It is clear that some changes to the current PURPA scheme will indeed occur, and that the initial period of overt favoritism enjoyed by some PURPA developers may be drawing to a close by the end of this year. See, B. Richards, "Cogenerated Power Irritates Utilities: Growth Could Hasten Industry's Deregulation," The Wall Street Journal, October 23, 1985, p. 6; W. Alpert, "Running Out of Steam," Barrons, December 9, 1985, p. 40. But such a shift is normal and is to be expected in an evolving and maturing market.

In addition, the Coalition believes that it is necessary to begin focusing on the issue of the need and justification for maintaining a monopoly for the production of electricity in the future. This issue is becoming increasingly important, as evidenced by the fact that some nuclear powerplants are over budget by staggering amounts, and generate electricity at rates exceeding the cost of a cogeneration or resource recovery plant, which perform the same task, by an order of magnitude of 3 or 4 to 1.

In upstate New York, for example, New York State Electric & Gas Company's newest coal-fired station at Somerset began producing power in August, 1984, at a cost of 7.5¢ per kwh. Less than one hundred miles away, Niagara Mohawk's $5.1 billion Nine Mile Point plant will provide power by 1987 at levels exceeding 18¢ per kwh. J. Cook, "Nuclear Follies," Forbes, February, 11, 1985, p. 82. This occurs while the New York

Public Service Commission and the electric utilities vehemently argue that the 6¢ per kilowatt hour purchase rate for QF power provided by the New York Legislature may be a subsidy, leading to a rate in excess of full avoided costs.

The true concern of some utilities appears to be a fundamental fear of competition, which is based on the insulation that they have enjoyed over the years through operation in a regulated monopoly environment. In their inevitable quest to avoid competition, they have attempted to cast the debate as an "excess capacity" issue, and to question the need for QF power in light of a potential surplus of power. However, as concluded by Roger Sant in America's Least-Cost Energy Strategy: Creating Abundance (McGraw-Hill, 1985), p. 132:

> Even more pertinent to the debate over competitiveness is the fact that decentralized technologies are now available to produce electricity at costs below that produced from new coal or nuclear plants. Cogeneration and small powerplant technologies provide strong competition for traditional utility power designs.

If QF rates are properly established at the utilities' full avoided costs, there should be no glut of electric power supply by QF's, by definition. If the supply is too large, it may mean that the price is too high. When allegations of a glut have been made, however, they are usually derived from information regarding QF's that may not reflect actual development, such as FERC filings for QF status. With a current shakeout factor of 50% on such applications, the alleged glut of QF power is likely to be overstated.

Generally, the Coalition submits that it may not yet be possible to fully or adequately evaluate the penetration and long-term benefits of PURPA, and that such evaluation needs at least an additional five years of actual experience. Only on such a basis can a true analysis be made as to the effectiveness of the original legislation, the FERC regulations, and the still-developing state programs and policies to implement them nationwide.

VI. RATEMAKING ISSUES UNDER PURPA

One of the most difficult issues in implementing PURPA has been the computation of purchase rates for cogenerated power. The literature and state proceedings have led to varied and creative approaches. Although this flexibility and diversity has been a source of confusion and uncertainty to some, it has also been one of the strong points of PURPA and its implementation by the states. The Pfeffer, Lindsay Study generally recognizes that the states have, in the majority of instances, performed this task well. Yet it presented several isolated instances as necessitating closer attention, to which the Coalition responds as follows.

PURPA provided only the barest framework to guide each state in establishing full avoided cost rates for the sale of power by QF's; the rates, terms and conditions for interconnection between QF's and utilities; and other related implementation issues. The FERC regulations promulgated in 1980 provided further guidance, but intentionally abstained from providing specific formulae or criteria in an effort to preserve maximum flexibility for the states in the implementation of PURPA. It was this flexibility which served as the basis for upholding the constitutionality of PURPA in 1982. FERC v. State of Mississippi, 456 U.S. 742, reh'g denied, 458 U.S. 1131 (1982).

As a result of this scheme, it was inevitable that the various states PURPA implementation proceedings would yield some different and even unconventional results. See C. Wooster, "Cogeneration: Revival Through Legislation," 87 Dickinson L. Rev. 705, 771-75 (1983). The majority of states, when faced with this task, responded in a manner that generally placed the responsibility on individual utilities and QF's to negotiate over rates, and other contract terms and conditions, rather than establishing a detailed regulatory scheme, e.g., Texas (initially), New Jersey, Pennsylvania, Connecticut (initially), and Michigan.

Other states have devised extremely detailed rules that have either favored the PURPA industry through concrete incentives, or weighed it down with new regulation, e.g., California, Connecticut and Idaho. The evolving shift toward burdensome state regulation is causing concern; QF's have been effectively deregulated at the federal level, yet, ironically, are being effectively re-regulated at the state level.

As a result of, and in some instances in spite of, these state regulatory developments, cogeneration is rapidly displacing the "natural monopoly" myth and modifying the market position of electric utilities. Cogeneration is serving as the new comparative surrogate in many state rate proceedings for electric utilities--a private sector yardstick to validate and confirm the presentations of electric utilities with regard to future costs, needs for capacity, etc. Instead of the monolithic electric utility at the center of regulation, we are witnessing a shift towards the ratepayer as the primary focus of the state commissions' concern. This shift in focus is the result of the need for state commissions to cope with issues such as rate shock, long-term fixed price supply contracts, excess capacity in some jurisdictions, and rapidly escalating rates for service irrespective of fuel cost declines. (See Attachment 2.) By restating the marketplace as the principal arbiter of prices, cogenerators, small power producers, and other providers of electric services can thrive--and those utilities which embrace competition will also thrive.

The cogeneration industry has assumed a leadership role in seeking changes in regulation. But the industry also recognizes that the changes it has sought are not perfect. Some states have needed to alter course and engage in self-corrective measures to adjust their PURPA implementation, *e.g.*, Texas, California, Idaho, Montana, or Colorado; or to accelerate their implementation after a slow start, *e.g.*, Michigan, New Jersey, Massachusetts, Connecticut, or Utah. Contrary to the Pfeffer, Lindsay Study implications, however, these efforts have been undertaken in good faith. Bona fide state policies and legal obligations were being fully satisfied, and development was proceeding consistent with federal law, subject to some mid-course corrections as greater experience and sophistication was brought to bear.

Presented below are some of the important issues that are being faced by the FERC, state regulatory commissions, and the QF and utility industries today, and which the Coalition believes are worthy of consideration by the Committee.

A. Level Playing Field Requirement

The Coalition submits that parity in the market for electricity generation will not be effectively established until the same basis for avoided costs and related methodologies and computations is applied uniformly to all sources of power from whatever source derived, whether from new electric generation stations, existing plant refurbishment and life extensions, electricity imports, dispersed power sources, or other sources. The Coalition believes that, if avoided costs are calculated and applied uniformally to all power sources, greater agreement on methodologies, more stability for future planning, and an increased likelihood of supportable responses to the vexatious question of what constitutes full avoided cost payment levels for the future will be the end result. To fully achieve this result, however, access through the transmission system must be more open, on a non-discriminatory basis, in order to facilitate economic efficiencies and decrease cost supply options to satisfy ratepayer demands. Additional comments regarding transmission access issues are discussed in detail below.

B. Value Pricing in Establishing Rates

The concept of value pricing, which is closely related to the level playing field concept discussed above, is gaining popularity among some state public utility commissions. The basis for value pricing is the increasingly widespread belief that all costs associated with the construction of new electric capacity by utilities should be carefully scrutinized. The primary reason for this belief is the recognition that cost overruns for large projects may not have been fully justified, or carefully managed by the utility working with its general contractor. Although state public utility commissions have historically applied value pricing to nuclear power projects, where in some cases construction costs overruns were extensive, value pricing in other situations is now gaining popularity in states such as California, New Jersey and Illinois.

It is noteworthy that value-based pricing already applies directly to small power production and cogeneration projects wherein the owner/builder assumes the total risk of designing its facility to meet the cost upon which project economics are based. It is the owner/builder that must live with cost overruns or other unfavorable capital cost economies. Further, the ratepayer is not placed in a position of subsidizing any cost overruns or design or construction errors attributable to additions of capacity from these sources. That risk is placed entirely upon the developer. In contrast, until recently, electric utilities were passing through cost overruns, costs for incomplete plants, and other management costs directly to the ratepayer.

Value pricing examines what the value of the additional capacity is to the ratepayer and consumer. The public utility commission, in reviewing rate cases, must make a judgment as to whether the costs of capacity additions are totally warranted. With the value pricing concept, new additional capacity, whether from cogenerators and small power producers or from utility facilities, is placed on an equal basis. More often than not, it is apparent that capacity from the cogenerator or small power producer will provide cost savings for the ratepayer and for the utility purchasing the power from such sources.

All new sources of electricity should receive the same rates whether they are built by utilities or third parties. Utilities should receive QF rates for their own new projects as well as paying QF rates to third parties who bring in new projects. In this fashion, the utilities will have a very strong incentive to see that QF rates are set correctly, and that they are properly adjusted to keep up with changing conditions. Placing the electric utility in this position will essentially guarantee that their estimates of QF prices will be as sensitive, realistic and accurate a reflection of market realities as possible.

Value pricing, in conjunction with better QF access to the transmission system, can facilitate maximum economic efficiency, from both a rate and transmission perspective. It also would effectively eliminate the need for adjusting the current 50% ownership limitation under PURPA since virtual parity in rate treatment for power purchases would exist. See, Roe & David, "QF Pricing: Issues and Implications." Paper presented before California Public Utilities Commission, 5th Annual Conference, March 25, 1985.

C. Ratepayer Impacts Resulting from the Full Avoided Cost Standard

In light of various positions espoused by the Pfeffer, Lindsay Study regarding full avoided costs, it is interesting to also evaluate a separate study conducted for the DOE Office of Industrial Programs on The Potential Detrimental Effects of Cogeneration Development on Utility Costs: A Preliminary Assessment. Prepared for the U.S. Department of Energy, February, 1986, by Hagler, Bailly & Company (hereinafter the "Hagler, Bailly Study") (Attachment 11). This study relied more upon quantitative measures than upon the anecdotal analysis techniques brought to bear in the Pfeffer, Lindsay Study.

In determining whether detrimental effects occurred from cogeneration development, a review was conducted of average utility costs by selecting thirteen utilities for review and assessment, including: Boston Edison, Central Maine Power, Central Power & Light, Consolidated Edison, Commonwealth Edison, Florida Power & Light, Gulf States Utilities, Houston Lighting & Power, Niagara Mohawk Power, Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, and Texas Utilities Electric. These utilities were selected because they had a relatively high level of cogeneration penetration, high levels of buy-back rates for power, and represented a good geographic distribution of utilities nationwide. A detailed review of the most recent operating statistics for these electric utilities is included in Attachment 11 to this testimony (See, Exhibit 1 of the Hagler, Bailly Study).

The Hagler, Bailly Study concluded that there is only one basis upon which industrial cogenerators selling electricity to a utility could detrimentally affect the utility's average cost of electricity for the short-term, although long-term impacts would be neutral or positive. This could occur through the use of long-term firm price contracts. Specifically, the use of levelized firm prices, which have been used at times for small power production facilities--rather than cogeneration projects--could cause near-term increases in average utility costs, but would reduce average costs in the long-term.

The Hagler, Bailly Study further indicated that for each electric utility examined, three utilities purchased cogenerated electricity at a price lower than the average price paid for all purchased electricity on its system (Attachment 11, p. 17). During 1984, Houston Lighting & Power Company ("HL&P") paid 6% less than its system-wide average price, and Gulf States Utilities paid 33% less for each kwh purchased from cogenerators. Moreover, during 1984, Texas Utilities Electric Company purchased cogenerated electricity at a price nearly 20% less than the total average cost of electricity from all other sources on its system. Id.

This represents a marked difference from representations made recently by various Texas utilities regarding the current state of cogeneration development within the state, and is more consistent with the 1986-87 Energy Efficiency Plan HL&P submitted to the Public Utility Commission of Texas. In that plan, HL&P proudly confirmed that "the net present value of the capacity cost savings that our customers will see over the ten-year life of our three firm capacity cogeneration contracts . . . is approximately $150 million." (Section D, p. 1 of 21) This savings was attributed by HL&P to its negotiating capacity payments to QF's at levels which were lower than its estimates of avoided capacity costs. (Id. at 8 of 21) According to HL&P: "Additional savings will be realized by our ratepayers due to a 1% discount off our avoided cost for firm energy supplied over the ten-year term under two of these contracts." Id.

Finally, it should be noted that only three electric utilities described in the Hagler, Bailly Study purchased more than 3% of their total electricity supply from cogenerators and small power producers (Attachment 11, p. 17). During 1984, Central Maine Power purchased 11%; Houston Light & Power purchased 15%; and Pacific Gas & Electric purchased nearly 4% of their total electricity supply from these dispersed power sources.

Ultimately, the Hagler, Bailly Study concluded that no adverse or detrimental affects to utility customers should exist over the long-term as a result of utility purchases from QF's.

D. Open-Ended Avoided Cost Contracts

PURPA is very clear in stating that the utility should pay its full avoided cost to QF's for purchased power. Nonetheless, the very fact that avoided costs are difficult to determine and forecast creates an obstacle for financing a project. Many financial institutions, uncertain of future avoided costs of most electric utilities, are unwilling to issue debt where the revenue stream is open to question over the project life. This is particularly true of electric utilities going through major changes in generation mix and power purchase arrangements. While it is likely that avoided costs will go up for all utilities over the long-term, assurances cannot be provided with regard to how much these costs will rise and when in specific cases.

It is safe to conclude, however, that simple avoided cost contracts alone are insufficient for financing most QF projects and are frequently rejected by financial institutions. A backstop to the avoided cost contract is almost always required in the form of a financial guarantee and/or restrictive escalation provisions in fuel supply agreements to ensure that minimum revenues and operating costs are kept in balance.

One approach to alleviate the uncertainty associated with avoided cost-type contracts is for the state public utility commission to encourage the use of floor prices as a means of providing a guaranteed revenue stream during the early years of a long-term contract, with the utility sharing in the avoided cost savings in the later years of the project. This is currently being explored in New York with respect to the Niagara Mohawk system. This balanced approach would achieve two objectives:

1. A backstop would be provided for the project, by the utility company, assuring a minimum price and subsequent energy revenues;
2. The utility would be permitted to mitigate risk against future costs of purchase power by providing savings in the later years of the project.

It should also be noted that various pricing requirements are currently being dictated by the financial community as support for project financings using non-recourse debt. With the additional expense of collateral support measures like letters of credit, and the general unavailability of necessary insurance coverages, these requirements have assumed growing importance and have impeded the development of sound projects.

E. Standard Contracts

Developers of qualifying facilities often face severe disadvantages in terms of access to information and the ability to bear transaction costs. The collection of information is expensive and the electric utility, which possesses superior information relating to the underlying issues being negotiated, has a relative advantage. The electric utility's cost of information is normally much lower than that of the QF, which generally does not engage in a large number of transactions, and thus cannot spread the fixed costs of information development over many negotiations. Moreover, if prudent, the electric utility costs are ultimately borne by its ratepayers, just as are the costs of rate cases, litigation and Commission proceedings.

The establishment of a uniform statewide contract for the purchase of electric power by QF's from electric utilities would help to equalize the bargaining position of the parties and would more accurately reflect the useful exchange and production of information found in a competitive market. States like Florida, California, Utah, Michigan, Connecticut, Massachusetts, Idaho and Montana have recognized this factor. In addition, the establishment of a uniform contract results in the reduction of overall costs incurred by all parties and the prudent encouragement of the development of QF's. However, state commissions that adopt such contracts must also preserve the necessary flexibility to modify the standard contract where appropriate, in recognition of differences between technologies, financing requirements, and other legitimate concerns.

If QF rates have not been appropriately established in a particular state, the appropriate remedy is not to abandon the standard offer approach, but to adjust the rates upward or downward. It is reasonable to develop a pricing approach that ensures that, at the signing of the cogeneration contract, the cogenerated power is not more costly than it would have been from the utility's next plant. In addition, the energy price component could be tied to market indications appropriate to the avoided plant, so that changes in such indications are reflected in the price paid to the cogenerator. [7]

Even with the provision of standard contracts, nonstandard contracts will arise, generally involving some type of debt guarantee, levelized payment, or floor payment which reduces risks for QF's and shifts those risks for a period of time to others in the transaction. Usually, these nonstandard terms are demanded by the source of financing to the QF developer. These terms have become more frequent in the face of state regulatory instability, continuing shifts in federal tax planning requirements, and erosion of historical insurance coverages. In return for assuming such risks, ratepayers typically are afforded some reduction on avoided cost payments. See, Pfeffer, Lindsay Study, p. 5.48.

F. Utility Commission Intervention in Signed Contracts

Some recent power purchase agreements with electric utilities include provisions that specifically allow for state public utility commission intervention to change the price that the utility would pay for the power, even after the contract has been agreed upon between the utility and the cogeneration project developer, e.g. Michigan and New York. While this intervention may be legal in certain states, it nonetheless creates doubt on the part of a QF project lender as to whether the utility commission might deny some part of the revenue stream upon which the lender is relying to cover debt for the project. The result of this uncertainty may be to delay or even deny financing to a project that may be otherwise meritorious.

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[7] By analogy, an electric utility, once it has built a plant, cannot go back and reprice it, just because interest rates or other costs decrease in the future. The utility must recover what it spent, not what it might have spent. The same is true for cogeneration and small power producers who also have to make construction and long-term contracting and financing decisions from the outset.

A more appropriate solution is to allow the contract between the developer and the utility to be reviewed by the state public utility commission for a sixty-day period, with final approval or denial to follow thereafter. Once the approval is given, however, the terms and conditions in the contract should be neither reversible nor subject to retroactive review, as has been the case in California, New Jersey, Texas and Connecticut. Better policy guidance from the FERC consistent with its own regulations could effectively remove this source of instability.

G. The Decremental Allocation Of Power Purchase Agreements

In some states, QF power purchase rates have been established on the basis of the value of decremental capacity to the utility company. While this concept has merit, particularly to the utility company, it has proven to be counterproductive in certain situations. The procedure generally works as follows: The utility establishes a first decrement capacity, which has the highest value to a utility, and a price which it is willing to pay for the first decrement of capacity. QF developers subsequently competitively bid the price they are willing to accept for power sold within that decrement of capacity. Once the first decrement has been filled by the utility based on its acceptance of the competitive QF offers, QF's competitively bid for decrements 2, 3, 4, etc., albeit at lower respective prices, which they are willing to accept for power sold to that utility.

Although this concept is not without merit, it can be counterproductive in that, in the interest of securing a power purchase contract, a developer may be competing against other QF's to the point where the bid price for the power sold from its facility may be lower than the level that the economics for the project can support. The net result may be that many QF projects allocated to the lower decrements of capacity of the utility may have revenue too low to cover project ownership and operation costs. Ultimately, the overall effect may be that fewer QF projects are built. Instead, those projects in the higher priced decrements, while not moving forward, take up valuable avoided cost allocations, and other developers wanting to construct projects fail, even though they may be more capable of completing the project.

While the concept of assigning power purchase agreements based on decrements of capacity needed by the utility company does have its drawbacks, it can be improved significantly with several major changes in the approach. One change would be to allow those projects to continue within their own decrements only if they complete certain key milestones, such as completion of financing commitments, permitting, engineering and construction contracts, and the like, by certain milestone dates. Failure to do so should result in those projects being "bumped" from the hierarchy of power purchase agreements, or being required to pay liquidated damages. Second, a front-end payment by the QF to the utility could weed out the conceptual projects, which are unlikely to be completed, from those projects with a higher likelihood of success and ratepayer benefits.

The Coalition notes that Maine, Connecticut and Texas seem to be most effectively working through this system. Oklahoma and Massachusetts currently have this approach under evaluation. The Pfeffer, Lindsay Study also appears to support this approach as a state level prerogative and which may be appropriate where QF capacity exceeds power demand in a particular jurisdiction.

H. Assurance of Just and Reasonable, Non-Discriminatory Standby Rates

The Coalition believes that there should be a full review and evaluation of standby, supplementary and maintenance power rates of all electric utilities and of the consistency of their implementation under PURPA. See, 16 U.S.C. 824a-3(b), and 18 C.F.R. §292.305. Both the FERC and the state public service commissions should undertake such a review, leading to the implementation, where necessary, of new state tariff provisions governing those services on a just and reasonable, non-discriminatory basis. Such implementation should include the removal of onerous reliability provisions, unjust demand ratchet clauses, and other disincentives associated with these services.

The number of instances in which this basic statutory responsibility has been ignored by electric utilities since 1978 is startling. For example, fully eight years after enactment of PURPA, electric utilities located in states like Michigan, Illinois, Iowa, and Missouri still do not have standby service tariffs in place.

Standby, maintenance and supplemental power rates and interconnection charges should not be set so that they become barriers to the implementation of cogeneration. The rates for such services and terms and conditions upon which they will be offered are frequently overshadowed by the issue of the appropriate full avoided cost purchased power rates from QF's. However, for most small-to-medium-sized cogeneration facilities, which are designed to supply the user's partial or full load, standby, supplementary and maintenance rates can be far more important than avoided cost rates. Commissioner Stalon made that point in his dissent in FERC's Alcon decision, Alcon (Puerto Rico), Inc., 32 FERC ¶61,247 (1985), when he stated: "If [the customer] cannot be assured backup power at reasonable rates from PREPA [the utility], a decision to cogenerate becomes far more difficult, if not impossible, however favorable the economics on the generation side of its proposed project."

If the user can reduce his total energy costs and pay back his capital costs within a reasonable period, then he knows what his investment must be and can decide accordingly. But, if he does not understand a major part of his standby charges, then he will not be able to make the necessary calculations to determine total energy charges and may, therefore, not make the investment. The state commission must set rates that are reasonable and non-discriminatory and are structured so that a potential investor in cogeneration can determine his costs in advance.

There are many ways to determine reasonable standby rates, and the various state commissions should be encouraged to undertake a thorough review of existing rates and develop appropriate methodologies. By way of illustration only, the Coalition would like to provide the Committee with an example of one such methodology, which is incorporated in a comprehensive order recently issued by the Connecticut DPUC (the "Authority") on, December 12, 1985:

> During the proceeding, the utilities moved from supporting demand ratchets more towards minimum charges. The Authority believes that the concept of minimum charges is more easily understood and acceptable to customers and therefore should be developed rather than demand ratchets. Most parties agree that minimum charges are appropriate to recover fixed costs imposed on the system by partial requirements customers. However, which costs to include in the charge is an area of dispute.
>
> The Authority believes that most distribution costs should be included in a minimum charge, but transmission and generation costs are not appropriate. United Illuminating states 'while it can be argued that no single customer, except in highly unusual circumstances, affects the amount of investment required in the production and transmission system, the engineering and construction of the

> distribution system can be affected by an individual.'
>
> The Authority will order the Companies to develop a minimum 'reservation' charge made up of 90 percent of distribution costs allocated to full requirements customers. This rate shall be in dollars per kw and will be monthly for each kw of capacity required to provide backup regardless if backup or maintenance service is actually used.
>
> A full demand charge should apply when standby service is actually used. A demand charge is appropriate due to demands imposed on the system of unscheduled outages during peak periods. The demand charge for backup service will be the same rate as the applicable general service tariff. These rates include distribution, transmission and generation costs. Demand which occurs during system peak has the same effect on costs regardless of its duration. Fixed costs do not vary with kwh usage, therefore it is not appropriate to prorate the demand charge based on kwh usage or to include demand costs in the kwh charge as proposed by some intervenors. No demand ratchet will apply. Since fixed costs attributed solely to the customer will be collected through the minimum charge, to also have a demand ratchet would double collect some fixed costs. An energy charge, appropriate to the class of a customer of a similar size, will apply when standby service is required. This is appropriate to recover variable costs of generation. When standby service is needed, a customer would be billed the greater of the minimum bill or the amount determined by applying the demand and energy to actual usage.

Other states have established standby rates which adopt different methodologies. The important point is that many states have not yet undertaken the necessary review, and should be strongly encouraged to do so consistent with PURPA.

The need for a review, and ultimately the guarantee of such services at cost-based rates and under appropriate terms and conditions of services, is further heightened by the recent decision of the FERC in Alcon (Puerto Rico), Inc., supra. In the Alcon decision, the FERC placed certain restrictions on the ability of third-party financed cogeneration facilities to receive the standby, supplementary and maintenance power services guaranteed by Section 210(e) of PURPA. The Coalition and other interested persons have sought rehearing of the FERC decision, and these requests are still pending at this time. In the interim, however, or in the event that rehearing is not granted, the ability of a cogeneration facility to obtain such services pursuant to state law requirements becomes paramount.

The FERC ruling effectively held that a consuming facility, or user, whose energy producing facility is owned by a separate source, does not have a cogenerator's right to standby power from its utility. This will curb the user's financing choices and leave uncertainty about which types of project arrangements will entitle the user to standby power pursuant to Section 210 of PURPA. The Commission's decision in Alcon will result in state regulatory commissions and local utilities effectively controlling a cogenerator's right to receive standby, maintenance and supplemental power, which is inconsistent with PURPA, and will constrain the ability of project developers to finance cogeneration projects. This will occur through the elevation of the project's perceived regulatory risks to a higher level--obstructing successful financing efforts.

The Coalition therefore urges the Committee to ensure that standby, supplemental and maintenance power services are available to qualifying cogenerators at just and reasonable non-discriminatory rates.

VII. ELECTRIC UTILITY OWNERSHIP ISSUES

Growing political pressures have been mounted to modify the current limitations on electric utility ownership of QF's under PURPA. However, we are not aware of substantive policy support or evidence presented in support of this position. In considering the electric utility ownership issues, the Coalition believes that further consideration should be given to the following factors:

1. Typically, an electric utility in a joint venture structure has no need to own in excess of 50% of the equity investment in a QF. This is consistent with current project financing strategies, accounting requirements under FASB standards, and presumed long-term interest in protecting off-balance treatment of such investments.

2. No meaningful data or analysis has been provided to indicate that penetration of QF development somehow would be increased, or enhanced, with a related electric utility ownership position. No quantifiable information has been developed to date, nor has the FERC been convinced in its review of these attendant issues in recent cases, including Ultrapower 3, KP Diversified Investors, and CP National, that a relaxation of this policy standard is in order.

3. There has been no analysis or meaningful evidence to indicate that the current standard has not operated as originally intended by the framers of PURPA in 1978. This standard was developed to provide a balance in various markets, recognizing the monopsony position of the electric utility in purchasing the electric output of the QF facility.

4. An investigation has been underway since 1984 by the Justice Department regarding acts and practices by electric utilities with respect to PURPA. A change in the current legislative provisions regarding utility ownership would be premature until publication of the results of the investigation.

5. Several states, such as California, Connecticut, New Jersey and Michigan, are reviewing these issues and should be permitted to proceed as a means of providing an independent basis of analysis.

Moreover, the 50% utility ownership limitation has not posed an impediment towards the full development of separate generation projects within the electric industry. These projects have been developed, under the leadership of major construction and AE firms, on a non-PURPA, non-qualifying facility status. They are being developed as unregulated generation projects, with various ownership interests, relying upon presentation of the projects for review and approval before the FERC as non-QF projects. This trend indicates that, notwithstanding the 50% ownership limitation established by the FERC regulations implementing PURPA, there are a variety of generation development and operating options for electric utilities under existing law--through QF's, through unregulated generation companies, and through other traditional pursuits.

VIII. TRANSMISSION ISSUES

The Coalition submits that a strong policy in favor of open access to transmission services should be endorsed by the Committee. Access to transmission services has become increasingly important to both traditional (i.e. regulated and municipal utilities) and non-traditional (i.e. qualifying cogenerators and small power producers) participants in the electric utility industry. Moreover, the availability of transmission services is necessary to foster a competitive environment in electric markets, which will ultimately inure to the benefit of the consumer.

While there is growing interest in decentralized power sources in this country and voluntary wheeling arrangements remain prevalent between electric utilities, [8/] many electric utilities are reluctant to wheel power on behalf of QF's and other decentralized power sources such as hydroelectric projects. The predominant reasons for this have been: 1) the lack of mandatory federal provisions compelling an electric utility to wheel electric power upon the request of a decentralized power source; 2) the fact that electric utilities, on a whole, have not yet realized that increased wheeling is in their own self-interest; and 3) the conflict between federal and state jurisdiction over wheeling transactions.

A. Impediments to Voluntary Transmission Arrangements

The ability of a QF to wheel its power, over the transmission lines of the utility in the area where the QF is situated, to other utilities which may have higher avoided costs can be critical to the economic viability of many QF projects. *See*, L. Catalano, "Cogenerators Seek to Expand Markets Through Wheeling," *Power*, March, 1985, p. 35ff. However, under the present FERC rules a QF can wheel its power

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[8/] While there are approximately 1,065 transmission service agreements on file at FERC and over 1,400 voluntary power transfers since 1976, these all were limited within the electric utility industry itself. Therefore they do not provide a meaningful basis to evaluate QF requests or requirements for increased wheeling.

to another electric utility only with the consent of the adjacent utility and any other intervening utility. 18 C.F.R. §292.303(d) (1985). If a utility chooses not to wheel, or if the QF does not agree to the wheeling of its electrical power, that utility retains its obligation to purchase from the QF. If the QF and all intervening utilities agree to wheel the power, however, then the remote utility to which the power is made available must purchase such power. Id.

Since electric utilities do not have a requirement under Section 210 of PURPA to transmit power on behalf of QF's, the QF often cannot secure higher market-based rates, and does not have the benefit of multiple market opportunities. As a result of this regulatory scheme, the development of economically efficient QF's is often frustrated. Moreover, a remote electric utility which may be willing to purchase power from the QF, but cannot get this power transmitted to its system, may be denied the benefits of low cost imported power.

The Coalition submits that, ultimately, consumers will be disadvantaged as a result of the constraints described above. For example, assume that a QF located in the service territory of Utility A can produce power at a cost of 3¢/kwh. Further assume that Utility A's avoided cost purchase rates are only 2¢/kwh, but Utility B, with which Utility A is interconnected, has avoided cost purchase rates of 4¢/kwh. Given these assumptions, the QF could not economically generate power for sale to Utility A, but would sell power to Utility B. If Utility A will not wheel the QF power to Utility B, however, the potential economic advantages associated with alternate energy production (3¢/kwh vs. 4¢/kwh) will be lost. Moreover, ratepayers in Utility B's service territory may lose any possible benefit which would result from the negotiation of a purchase contract at a rate below Utility B's avoided cost rate.

If an adjacent or connecting utility does not agree to wheel the QF's power to another utility with a higher avoided cost, the only direct statutory authority on which a QF could arguably rely to compel transmission of the power of a QF is Section 211 of the FPA. This section, in conjunction with Section 212 of the FPA, permits the FERC to order wheeling, provided numerous statutory criteria are satisfied. However, due to the cumbersome statutory criteria contained in these sections of the FPA, as well as the requirement that an evidentiary hearing be held prior to issuance of an FERC order thereunder, the statutory scheme does little to encourage the transmission of power from QF's.

Moreover, QF's are not clearly identified as persons eligible to seek a wheeling order under these sections of the FPA, and it is not clear whether the utility to which power would be wheeled is allowed to petition the FERC in order to obtain a wheeling order. In reality, the FERC has never acted favorably on any such requests, primarily due to the onerous burdens and complicated factual showings required by Sections 211 and 212 of the FPA. Five such applications have been filed since 1978: one was denied; two are pending; and two were settled.

As an alternative to Sections 211 and 212 of the FPA, a QF currently has only limited and indirect options available if a utility is not cooperative in wheeling negotiations. The QF may resort to filing an antitrust law suit or instituting a proceeding at the Nuclear Regulatory Commission, if applicable. Both of these options, however, are extremely costly and time-consuming, and consequently are not viable means by which to assert underlying rights and seek the transmission of power by most QF projects.

Another impediment which has resulted in demand for transmission services not being met is the uncertain and potentially conflicting roles of federal and state commissions regarding the regulation of transmission services. It is well settled that the FERC has jurisdiction over the rates for the transmission of electric energy in interstate commerce. But the FERC does not regulate "facilities" used solely in local distribution, and may not assert jurisdiction over the rate for transmission services if the agreement in whole does not constitute a single transaction which constitutes the transmission of electric energy in interstate commerce. Consolidated Edison Co. of New York, Inc., 15 FERC ¶ 61,174 (1981). Thus, arguably, if distribution facilities are the exclusive facilities involved between connections, the state commissions may have authority under their enabling legislation to direct the utility to wheel power for the QF, particularly if the utility does not operate in interstate commerce. In most instances, however, it is likely that a combination of distribution and transmission facilities will be involved in the proposed transmission of power from a QF.

The resistance of electric utilities to wheel power from decentralized power sources appears short-sighted and ignores the potential benefits to the utilities' own operations. For example, capacity short utilities may be able to import low cost generated power without undergoing capital intensive construction programs. Indeed, the potential for QF and other decentralized power sources to reduce energy costs can be demonstrated in a wide variety of commercial, industrial, and residential applications. As more QF projects and other decentralized power sources come on-line, the increased availability of the power they generate can yield capacity for longer term growth and increased system reliability.

B. Current Attempts to Stimulate Voluntary Transmission Arrangements

Notwithstanding the statutory impediments currently surrounding the FERC's wheeling authority, the Coalition believes that the FERC does have the means to stimulate increased transmission system accessibility. For example, the Coalition notes that the FERC is currently experimenting with a bulk power sales program under which utilities are granted certain pricing flexibility as a means of stimulating competition between suppliers. See, Public Service Co. of New Mexico, 25 FERC ¶ 61,149 (1983). Under this program, participants are also obligated to provide transmission access to other participants, including cogeneration and other alternate energy producers. Participants subject to the FERC's jurisdiction must file wheeling tariffs with the FERC specifying non-discriminatory price and non-price provisions.

The Coalition urges the Committee to consider advising the FERC to extend the bulk power program, including the same type of transmission accessibility requirements, to other areas of the country as a means of encouraging wheeling services for QF's. The Coalition is aware that several utilities in various areas of the country have expressed interest in participating in bulk power marketing experiments and believes that the development of QF's would be greatly benefited by expansion of this program.

C. Fundamental Non-Price Terms and Conditions Applicable to Transmission Services

The Coalition also notes that the non-price terms and conditions of a transmission agreement can significantly affect the rate for transmission services. Although non-price terms and conditions are contract specific, the following terms and conditions will generally affect the allocation of costs, and therefore the wheeling rate: 1) voltage level; 2) type of power transmitted; 3) number and length of interruptions; 4) curtailment priority in emergencies; 5) types of facilities used; and 6) contributions in aid of construction.

Once the wheeling rate is determined, there are additional non-price terms which must be reflected in the wheeling contract. Examples of these terms and conditions include:

1. Provision for the safety and protection of line crews while doing work on company lines or equipment;
2. Provision for the protection of the operational integrity of company's system;

3. Provisions for limitation of harmonic distortion which may be introduced by a cogenerator on a company's system;

4. Provision for the prohibition of abnormal voltages, voltage fluctuations or harmonic content that would cause undue interference with other customer loads or company equipment;

5. Provision for special metering to measure the output of a cogeneration facility and detented metering in order to measure flows to the company and from the company; and

6. Provision for insuring production of adequate reactive power or, in lieu thereof, adequate compensation when the company is burdened.

D. The Need for a Market-Based Approach to Transmission Services

The Coalition believes that transmission services should take place under a free market system. If transmission services are based on such a system, there should be no circumstances under which expanded transmission services would not be desirable. Under a market based approach, the growth, or diminution, of transmission services would be controlled by economic, technological and environmental considerations derived from the marketplace. Moreover, a market based approach is necessary in order to further encourage the development of QF's, consistent with the goals of PURPA. Such increased accessibility will also inure to the benefit of utility ratepayers, who will be able to experience the benefits of low cost power associated QF generating efficiencies.

Finally, we urge the Congress to conduct further oversight hearings of the FERC and its NOI series seeking further administrative flexibility in this area.

IX. CONCLUSION

The emergence of cogeneration as a long-term contribution to national energy policy planning is contingent upon stable and balanced federal and state leadership. In order for cogeneration and small power to flourish, industry must be permitted, and indeed encouraged, to undertake forward-looking opportunities to gain greater control over energy costs, and thus enhance their long-term productive capabilities.

For cogeneration to succeed in the chambers of the Congress and in the various federal and state regulatory hearing rooms, it must succeed in the living rooms of our ratepayers and the board rooms of our corporations. It can and has started that process. But sometimes the relationships involved have become taxed. There is concern that the development of more QF's will exacerbate perceived excess capacity situations, leading to higher rates; and that price inelastic customers will be forced to bear an escalating share of the utilities' fixed costs, while more price elastic customers, like industrial users and hospitals, shift to self-generation.

These concerns, however, are tied to the maintenance of the same regulatory system which produces perverse results such as higher, rather than lower, rates resulting from excess capacity. The solution to these problems is to allow the market forces to work, and to discard the natural monopoly myth. The gas industry has started to witness this; the oil industry saw it in 1981; other industries have followed.

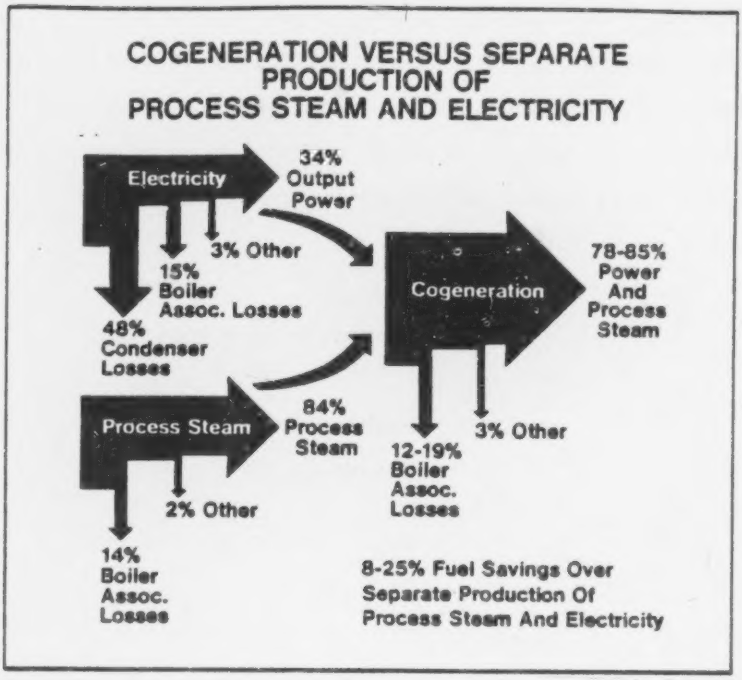
Today's opportunities include the incorporation of cogeneration in long-range energy plans and in electric utility supply forecasts. Cogeneration can meet the full market tests advocated by the Administration, if provided a fair and balanced chance. Accordingly, we encourage the Committee to engage in progressive, supportive initiatives to further the development of alternate energy sources, such as cogeneration, resource recovery, and small power production to promote energy efficiency, jobs, industrial competitiveness and related economies for the future.

Respectfully submitted,

Michael J. Zimmer
President

MJZ11/57

ATTACHMENT 1

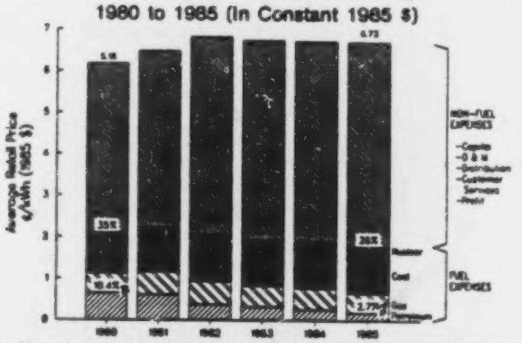

COGENERATION VERSUS SEPARATE PRODUCTION OF PROCESS STEAM AND ELECTRICITY
Electricity
34% Output Power
3% Other
15% Boiler Assoc. Losses
48% Condenser Losses
Process Steam
84% Process Steam
2% Other
14% Boiler Assoc. Losses
Cogeneration
78-85% Power And Process Steam
3% Other
12-19% Boiler Assoc. Losses
8-25% Fuel Savings Over Separate Production Of Process Steam And Electricity

"Process Steam and Cogeneration--A Diversified Market Opportunity for Electric Utilities," R. H. Quig. Paper presented at Fifty-Third Annual Executive Conference, Ebasco Services, Inc., September 27-29, 1982.

Attachment 2

Fuel Expenses as a Component of the Average U. S. Retail Price of Electricity

1980 to 1985 (In Constant 1985 $)



NOTE: In real dollars, the average electricity price per kilowatt-hour (to all sectors) has changed little in six years, while the fuel component has declined from 35 per cent to 26 per cent. Nonfuel expenses, especially capital costs of new power plants, have offset lower fuel costs. Oil costs have dropped even more dramatically, from 10 per cent in 1980 to less than 3 per cent in 1985. Even if the average cost of oil to utilities were to drop 50 per cent, the average retail price per kilowatt-hour would decline by only about one-tenth of a cent. Other cost increases would quickly offset any such decline.

SOURCE: "Federal R&D on Energy Efficiency: A $50 Billion Contribution to the U. S. Economy," American Council for an Energy Efficient Economy and Energy Conservation Coalition, March, 1986.

"Least-cost Utility Planning: Providing A Competitive Edge," C. Schneider, Public Utilities Fortnightly, April 17, 1986, p. 15.

ATTACHMENT 3

THE NUCLEAR FAMILY—FOOLS AND HEROES

[illegible] implicitly, the fools and [illegible] utilities on the various [illegible] of the table is the [illegible] the plants are ranked [illegible] including the [illegible] (AFUDC) [illegible] And what a dismal record it is, with costs ranging from $932 a kw to $5,192, from some of the lowest-cost new plants in the world to plants that are not even competitive with oil, never mind coal. The utilities think they're doing well if [illegible] coal is generally competitive with plants costing [illegible] or more [illegible]. The final column [illegible] rate increase the utilities may need as their new high-cost nuclear [illegible] How much depends less on the [illegible] cost of [illegible] than what proportion of the company's net property it represents.

Plant[1]	Utility	Ownership	Architect/ engineer	Construction manager	Reactor supplier	Total expected cost (billions)	Net capacity (megawatts)	Cost per kw	AFUDC as % of cost	Year ordered	Year of expected service	Gross rate impact[2]
Shoreham[3]	Long Island Lighting Co	100%	Stone & Webster	Utility	General Electric	$4.2	809	$5,192	35%	1967	1985	53%
Midland 2	Consumers Power Co	100	Bechtel	Bechtel	Babcock & Wilcox	4.0	818	4,889	30	1968	[redacted]	47
Nine Mile Point 2	Niagara Mohawk Power Co	41	Stone & Webster	Stone & Webster	General Electric	5.1	1,084	4,705	34	1971	1986	19
	NY State Electric & Gas Corp	18										20
	Long Island Lighting Co	18										12
	Rochester Gas & Electric Co	14										28
	Central Hudson Gas & Electric	9										20
Beaver Valley 2	Duquesne Light Co	14	Stone & Webster	Utility	Westinghouse	3.5	833	4,166	33	1971	1986	11
	Ohio Edison	42										17
	Cleveland Electric Illuminating	24										13
	Toledo Edison	20										25
Seabrook 1	Public Service of New Hampshire	36	United Engineers & Constructors	New Hampshire Yankee	Westinghouse	4.5	1,150	3,913	36	1972	1986	63
	United Illuminating	18										32
	Massachusetts Municipal Wholesale	12										—
	New England Power Co	10										6
	Central Maine Co	6										11
	Connecticut Light & Power	4										2
	Others	14										—
Zimmer 1	Cincinnati Gas & Electric	40	Sargent & Lundy	Henry J Kaiser Co	General Electric	3.1	810	3,827	35	1969	[redacted]	27
	Columbus & Southern Ohio Electric Co	29										4
	Dayton Power & Light	31										26
River Bend 1	Gulf States Utilities Co	70	Stone & Webster	Stone & Webster	General Electric	3.6	940	3,805	[illegible]	1972	1985	26
	Cajun Electric Power Coop	30										—
Limerick 1[4]	Philadelphia Electric Co	100	Bechtel	Bechtel	General Electric	1.8	1,055	1,682	31	1969	1985	33

"Nuclear Follies," J. Cook, Forbes, February 11, 1985, p. 82.

Hope Creek 1	Public Service Electric & Gas Atlantic City Electric Co	95 5	Bechtel	Bechtel	General Electric	3.8	1,067	3,561	24	1969	1986	23 7
Harris 1	Carolina Power & Light North Carolina Eastern Municipal Power Agency	84 16	Ebasco	Daniel Intl	Westinghouse	3.0	900	3,333	26	1971	1986	28 —
Millstone 3	Northeast Utilities New England Power Co Montaup Electric Co United Illuminating Co Public Service of New Hampshire Central Maine Power Others	65 12 4 4 3 2 10	Stone & Webster	Stone & Webster	Westinghouse	3.8	1,150	3,336	31	1973	1986	27 6 11 6 4 3 —
Clinton 1	Illinois Power Co Soyland Power Coop Western Illinois Power Coop	82 10 8	Sargent & Lundy	Baldwin Associates	General Electric	3.1	950	3,308	25°	1973	1986	50 — —
Vogtle 1, 2	Georgia Power Co Oglethorpe Power Corp Municipal Electric Authority of Georgia City of Dalton	46 30 23 1	Southern Services/ Bechtel	Utility	Westinghouse	7.2	2,300	3,273	34°	1971	1987, '88	11 — — —
Perry 1	Cleveland Electric Illuminating Co Ohio Edison Co Toledo Edison Duquesne Light Co Pennsylvania Power	31 30 20 14 5	Gilbert	Utility	General Electric	3.9	1,205	3,270	30	1972	1985	18 14 38 12 3
Marble Hill 1, 2	Public Service of Indiana Wabash Valley Power Assn	83 17	Sargent & Lundy	Utility	Westinghouse	7.0	2,260	3,097	30	1974	[redacted]	120 —
Fermi 2	Detroit Edison Co Wolverine Power Supply Coop	83 17	Utility	Daniel Intl	General Electric	3.4	1,100	3,060	31°	1968	1985	23 —
Washington Nuclear 2[a]	Washington Public Power Supply System	100	Burns & Roe	Bechtel	General Electric	3.4	1,100	3,045	—	1971	1984	—
South Texas 1, 2	Houston Lighting & Power Co City Public Service of San Antonio Central Power & Light Co City of Austin	31 28 25 16	Bechtel	Ebasco	Westinghouse	7.5	2,500	3,000	27	1973	1987, '89	11 — 13 —
Grand Gulf 1[b]	Middle South Utilities South Mississippi Electric Power	90 10	Bechtel	Bechtel	General Electric	3.4	1,250	2,724	46°	1972	1985	30 —
Callaway 1[b]	Union Electric	100	Bechtel	Daniel Intl	Westinghouse	3.0	1,150	[illegible]	37	1973	1985	42
Wolf Creek	Kansas Gas & Electric Co Kansas City Power & Light Co Kansas Electric Power Coop	47 47 6	Bechtel/ Sargent & Lundy	Daniel Intl	Westinghouse	2.9	1,150	2,222	32	1973	1985	63 44 —

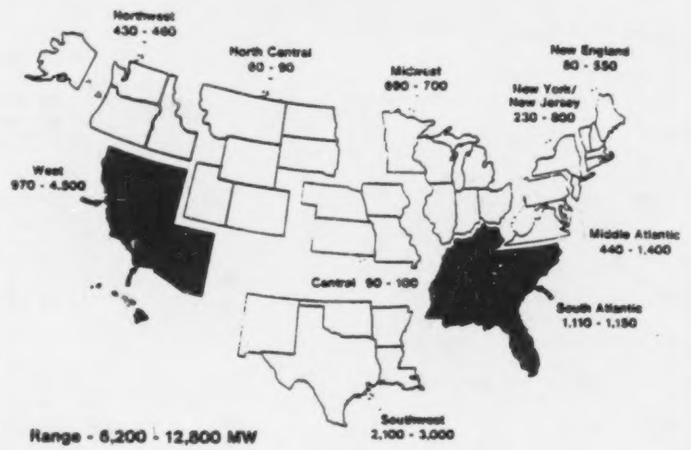
Waterford 3[d]	Louisiana Power & Light Co	100	Ebasco	Ebasco	Combustion Engineering	2.7	1,104	2,473	21	1970	1985	18
Diablo Canyon 1[e]**, 2**	Pacific Gas & Electric	100	Utility	Utility	Westinghouse	5.4	2,190	2,466	34	1966, '68	1985, '85	25
Palo Verde 1[d]**, 2, 3**	Arizona Public Service	29	Bechtel	Bechtel	Combustion Engineering	9.3	3,810	2,441	37	1973	1985, '86, '87	56
	El Paso Electric Co	16										89
	Southern California Edison	16										6
	Public Service of New Mexico	10										42
	Salt River Project	23										—
	SCA Public Power Authority	6										—
Bellefonte 1, 2	Tennessee Valley Authority	100	Utility	Utility	Babcock & Wilcox	5.7	2,664	2,134	60	1970	1989, '91	—
Susquehanna 2[e]	Pennsylvania Power & Light Co	90	Bechtel	Bechtel	General Electric	2.2	1,050	2,095	31	1968	1985	29
	Allegheny Electric Coop	10										—
San Onofre 3[f]	Southern California Edison	75	Bechtel	Utility	Combustion Engineering	2.3	1,100	2,045	40[a]	1970	1984	7
	San Diego Gas & Electric Co	20										7
	City of Anaheim	3										—
	City of Riverside	2										—
Byron 1[d]**, 2**	Commonwealth Edison	100	Sargent & Lundy	Utility	Westinghouse	4.2	2,240	1,866	39	1971	1985, '86	16
Braidwood 1, 2	Commonwealth Edison	100	Sargent & Lundy	Utility	Westinghouse	4.1	2,240	1,835	43	1972	1986, '87	16
Catawba 1[d]	Duke Power	25	Utility	Utility	Westinghouse	3.9	2,290	1,703	35	1972	1985	7
	North Carolina Electric Membership Corp	56										—
	Saluda River Electric Coop	19										—
Catawba 2	No Carolina Municipal Power Agency #1	75									1986	—
	Piedmont Municipal Power Agency	25										—
Comanche Peak 1, 2	Texas Utilities Electric Co	88	Gibbs & Hill	Brown & Root	Westinghouse	3.9	2,300	1,696	24	1972	1985, '86	18
	Texas Municipal Power Authority	6										—
	Brazos Electric Power Coop	4										—
	Tex-La Electric Coop of Texas	2										—
Watts Bar 1, 2	Tennessee Valley Authority	100	Utility	Utility	Westinghouse	3.9	2,354	1,672	33	1970	1985, '87	—
Summer 1[f]	South Carolina Electric & Gas	67	Gilbert	Daniel Intl	Westinghouse	1.3	900	1,446	24	1971	1984	25
	South Carolina Public Service	33										—
LaSalle 2[f]	Commonwealth Edison	100	Sargent & Lundy	Utility	General Electric	1.1	1,078	1,020	22	1970	1984	6
McGuire 2[f]	Duke Power	100	Utility	Utility	Westinghouse	1.1	1,100	932	33	1969	1984	8

[a] For [illegible]'s portion of the investment only. [b] The following plants under construction as of the end of 1983 do not appear on the table because they have been canceled or indefinitely delayed: Midland 1, Seabrook 2, Limerick 2, Perry 2, River Bend 2, Grand Gulf 2, Washington Nuclear 1 & 3, Yellow Creek 1 & 2, Hartsville A-1 & A-2. [c] The gross rate impact for investor-owned utilities was calculated according to the following formula developed by Salomon Brothers in *Nuclear Power in the United States* by Scott Sarsorius and Neal Kurzner (July 1984): gross rate impact = utilities' share of plant cost x 16%/1983 operating electric revenues of utility. The 16% represents cost of capital for the utility. [d] Low-power operating license: load fuel and test up to 5% power. [e] Full-power operating license: load fuel and test up to 100% power. [f] Commercial operation.

Sources: Utilities, Salomon Brothers, Atomic Industrial Forum, Donaldson, Lufkin & Jenrette, Forbes

ATTACHMENT 4

EXPECTED RANGE OF COGENERATION DEVELOPMENT BY REGION: 1981 - 1990 (MW)


Northwest
430 - 460
North Central
60 - 90
Midwest
690 - 700
New England
80 - 350
New York/
New Jersey
230 - 800
West
970 - 4,500
Middle Atlantic
440 - 1,400
Central 90 - 100
South Atlantic
1,110 - 1,150
Southwest
2,100 - 3,000
Range - 6,200 - 12,800 MW

"Process Steam and Cogeneration--A Diversified Market Opportunity for Electric Utilities," R. H. Quig. Paper presented at Fifty-Third Annual Executive Conference, Ebasco Services, Inc., September 27-29, 1982.

ATTACHMENT 5

COGENERATION EQUIPMENT OR DEVELOPMENT SERVICES REQUIRED

Item	Typical Supplier States
Thermal Equipment	
Combustion Gas Turbines	CA IN MN NJ NY OH TX
Steam Turbines	FL IA MA MN NY OH PA
Packaged Engine Systems	CT IL KS MA MI MN NY OH PA VA WI
Coal-Biomass Boilers/Stokers	CT GA IL MD MI NE OH OK PA TN VA WA WI
Waste Heat Recovery Boilers	CT GA IL KY MN NY NE OK PA VA WA WI
Electrical Equipment	
Generators	IL MA MI MN NJ OH PA WI
Switchgear, Transformers and Substations	GA IL IA MA MN NJ NY NC OH PA TX WI
Other Equipment	
Instruments, Controls, Wire and Cable	CA CO CT IL IA MA MD MI MN NJ NY OH PA VA WA WI
Pumps, Valves, Cooling Towers and Water Treatment	CA CO CT FL GA IL IN MD MA MI NJ NY OH PA TX VA WI
Piping	AL GA IL MD MO NY OH PA UT WV
Structural and Reinforcing Steel	IL IN MD OH NY PA WV
Design, Construction, and Financing	
Design, Engineering and Supervision	CA CO CT IL LA MI NJ NY OH PA TX UT
Construction Labor	KY NY OH PA WV
Construction Loans and Financing	CA GA IL KY NY OH PA WV
TOTAL	**Over 30 Supplier States**

These projected expenditures for this region's cogeneration are conservative in that they are for only 25 percent of the cogeneration potential in the states of Kentucky, Ohio, Pennsylvania, West Virginia and of New York. Also, the above tabulation is understated in that no allowance is included for secondary economic impacts within these typical supplier states, generally considered to add an additional 160 percent to the above direct purchases.

*Denote items where, as will be seen from the supplier state listings, most or a large share of the related purchases will likely remain within this region -- except of course for the secondary economic impacts of increased purchasing power which would also spread into other regions.

ATTACHMENT 6

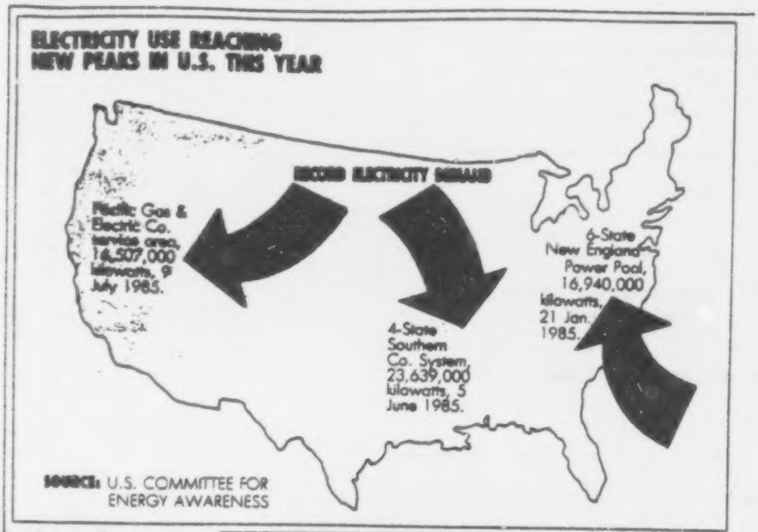
COGENERATION FACILITY LONG-TERM OPERATING IMPACTS

Type	Typical Supplier States
Maintenance Parts and Labor	
Gas Turbine-Generator	CA CO CT IN MN NJ NY OH PA TX WI
Steam Turbine-Generator	CA CO CT FL IA MA MN MO NY OH PA TN VA WI
Packaged Gas Engine Systems	CT IL KS MA MI MN NY OH PA VA WI
Boilers	CT GA IL KY MA MD MI MN MO NE NJ NY OH OK PA TN VA WA WI
Other Equipment	35 - Plus States
Water Treatment Chemicals, Lube Oils, Supplies, etc.	IL IN KY MD MI MO NJ NY OH PA TN VA WV TX
Direct Operating Labor	KY NY OH PA WV
Coal	
Purchases	KY MD OH PA VA WV
Rail, Truck and Other Transport	KY MD NY OH PA VA WV
Natural Gas	
Purchases	75% AR LA OK TX 25% KY NY OH PA WV
Gas Consumer Benefits	National Benefit
Electric Consumer Benefits	National Benefit
Other	
Local and State Taxes, Insurance	National Benefit
Federal Income Tax Payments	National Benefit
TOTAL	Over 38 Supplier States

These projected benefits from this region's cogeneration are conservative in that they are for only 25 percent of Ohio Valley potential in the states of Kentucky, Ohio, Pennsylvania, West Virginia and of New York. Also, the above tabulation is understated in that no allowance is included for secondary economic impacts within these typical supplier states, generally considered to add an additional 160 percent, or for customer cogeneration savings; nor is inflation included for future years.

*Denote items where, as will be seen from the supplier state listings, most or a large share of the related purchases or benefits will likely remain within this region -- except of course for the secondary economic impacts of increased purchasing power which would spread into other regions.

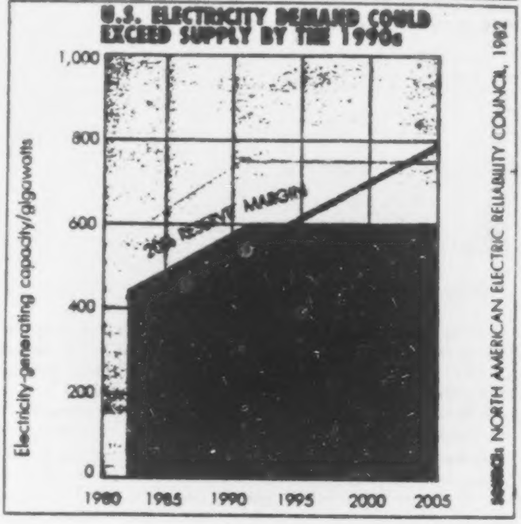
ATTACHMENT 7


RECORD ELECTRICITY DEMAND
Pacific Gas & Electric Co. service area, 16,507,000 kilowatts, 9 July 1985.
4-State Southern Co. System, 23,639,000 kilowatts, 5 June 1985.
6-State New England Power Pool, 16,940,000 kilowatts, 21 Jan. 1985.

ELECTRICITY USE REACHING NEW PEAKS IN U.S. THIS YEAR

SOURCE: U.S. COMMITTEE FOR ENERGY AWARENESS

(above) Regional demand for electrical power is up again in 1985. (right) Utilities may fall below 20 percent reserve margin for reliable service by 1993.



U.S. ELECTRICITY DEMAND COULD EXCEED SUPPLY BY THE 1990s

SOURCE: NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL, 1982

"Future Shock: The Coming Electrical Shortage," J. Beard, Constructor, November, 1985, p. 20.

ATTACHMENT 8

NATIONAL AVERAGE CAPACITY FACTORS FOR ELECTRIC GENERATING UNITS, BY TYPE

Plant Type	Capacity Factor 1973	Capacity Factor 1984
Oil-fired	38 %	12 %
Gas-fired	51 %	35 %
Coal-fired	53 %	51 %
Nuclear	45 %	52 %
Hydroelectric	50 %	45 %

Statement of Danny J. Boggs, Deputy Secretary, DOE, before the Senate Committee on Energy and Natural Resources, July 25, 1985.

ATTACHMENT 9

COST OF ELECTRICITY AND GAS FROM A WORKING
COGENERATION PLANT WITH FUEL COSTS OF $3.75 PER MCF
DATA IS FOR APRIL OF 1986

DAY OF MONTH	KWH PER DAY	BTU DEL. x 10,000	METERED NAT. GAS CF/DAY x 10	ELECT EFFICIENCY %	THERM EFFICIENCY %	ELECT COST $ PER KWH	STEAM COST $ PER M LBS
1	11,700	6,869	13,339	30.67	52.40	0.0173	4.32
2	11,740	6,809	13,217	30.85	52.42	0.0172	4.31
3	11,776	6,867	13,209	30.78	52.58	0.0173	4.30
4	11,786	6,782	13,294	30.79	51.91	0.0173	4.35
5	10,382	6,255	12,119	29.75	52.52	0.0174	4.38
6	10,232	6,344	12,063	29.46	53.52	0.0174	4.32
7	11,598	6,687	13,212	30.49	51.50	0.0173	4.41
8	11,644	6,680	13,281	30.45	51.18	0.0173	4.44
9	11,592	6,581	13,234	30.42	50.60	0.0173	4.49
10	11,624	6,644	13,274	30.41	50.93	0.0173	4.46
11	11,644	6,465	13,328	30.34	49.36	0.0173	4.61
12	10,214	5,997	11,876	29.87	51.39	0.0174	4.47
13	10,434	6,264	12,193	29.72	52.28	0.0174	4.40
14	10,820	6,297	12,286	30.59	52.16	0.0173	4.35
15	11,792	6,559	13,419	30.52	49.74	0.0173	4.56
16	11,700	6,504	13,364	30.64	49.52	0.0173	4.57
17	11,782	6,535	13,274	30.83	50.10	0.0172	4.51
18	10,072	5,874	11,370	30.77	52.57	0.0173	4.30
19	7,712	5,313	9,747	27.48	55.47	0.0178	4.30
20	8,160	5,469	10,451	27.12	53.25	0.0178	4.51
21	11,806	6,530	13,388	30.63	49.63	0.0173	4.56
22	11,800	6,608	13,322	30.76	50.48	0.0173	4.48
23	11,720	6,546	13,201	30.83	50.46	0.0172	4.47
24	11,744	6,716	13,340	30.58	51.23	0.0173	4.43
25	11,748	6,741	13,522	30.17	50.73	0.0173	4.50
26	9,136	6,094	11,348	27.96	54.65	0.0177	4.33
27	8,008	5,782	10,468	26.83	56.21	0.0179	4.29
28	11,800	6,873	13,769	29.76	50.80	0.0174	4.53
29	11,776	6,850	13,687	29.80	50.93	0.0174	4.50
30	11,720	6,546	13,201	30.83	50.46	0.0172	4.47
31	0	0	0	0	0	0	0
TOTALS	329,910	193,081	380,876	30.60	52.19	0.0176	4.39

-Industrial Co-Energy Systems, Inc., Grand Rapids, Michigan.

ATTACHMENT 10

May 30, 1986

CRITICAL NOTES ON DOE REPORT ENTITLED "EMERGING POLICY ISSUES IN PURPA IMPLEMENTATION"

The Department of Energy (DOE) report prepared by Pfeffer, Lindsay and Associates is a carefully written document. It offers the appearance of presenting both sides of the story in relationship tc the issues surrounding the Public Utility Regulatory Policies Act (PURPA), cogeneration and small power production development, the electric utility industry, and ratepayer equity. It is, in fact, a carefully contrived document which supports drastic and substantial recommendations, as in Section XIII, to alter the impact and goals of PURPA so that the electric utility industry will not lose its monopoly position for power generation to a competitive marketplace. This should not be surprising in a study funded by the DOE Office of Coal and Electric Power, which by its very nature implies an immediate bias toward coal-fired central stations.

QF Market Potential

In the background data presented in Section III, the authors write critically of early efforts to predict the potential for qualifying cogeneration and small power production facility (QF) development. The written comments on this early effort by both public and private sector sources (including the electric utility industry) border on the derogatory.

A great deal of effort has been taken by the authors to point out discrepancies in the data base which has been used by FERC and other groups to either support or challenge the validity of the effectiveness of PURPA. The studies conducted by Hagler-Bailly, Dun & Bradstreet/TRW, and Frost and Sullivan on the potential for cogeneration are extensively referenced. The wide range of potential that is referenced in these and other studies by EPRI and the Gas Research Institute illustrate considerable conflict in expectations based upon who was conducting the study, why they were conducting the study, and what their level of expertise in understanding the cogeneration market potential might have been prior to commencing the study. This lack of consensus on the part of different market research groups is not unusual in the energy field, and should not serve as the source of critical doubt. Moreover, benchmark studies are now underway by Hagler, Bailly and Company for FERC and by GKCO, Inc. for the gas industry to provide a complete data base of all operating cogeneration facilities by 1987.

All that notwithstanding, the authors briefly state, "As noted below, the preliminary projections of the impact of Title II of PURPA have proven to be surprisingly accurate considering the limited information on which they were based. Available data suggests that there has been a substantial growth in both cogeneration and small power development since the enactment of PURPA." (p. 3.13)

Policy Conflicts

In Section IV entitled "The Identification of Key Policy Issues in PURPA Implementation," the authors cite two studies sponsored by the DOE and the Office of Technology Assessment (OTA) which raised eleven possible policy conflicts. These policy conflicts are not policy conflicts with PURPA and the original goals and objectives of Congress in enacting PURPA or in the promulgation of the rules as set forth by the Federal Energy Regulatory Commission. In fact, they are policy issues which are in conflict primarily with the development goals of the electric utility industry and are improperly included in this document at this stage. The issues range from fuel choice for electric generation, cancellation or deferral of large scale powerplants, the financial integrity of the electric utility industry, plant life extension policies, equity for utility ratepayers, and environmental siting concerns.

The key issues that are raised by the authors and which are, in fact, documented through anecdotal evidence and discussed throughout the balance of the document are the following:

1. Requirements to pay QF's full avoided costs where some lower rate might provide adequate incentives for QF development and allow ratepayers to share in the benefits of lower cost cogeneration.

2. Requirements to pay QF's for purchases at rates in excess of full avoided costs including imprecise methodologies for avoided cost computations, energy payments which exceed the utility's marginal energy cost, requirements for payment of capacity credits when capacity is not needed by the utility, or requirements to purchase power where the power is less than firm or there is a likelihood of nonperformance by the QF.

3. QF purchase rates which understate the utility's avoided cost including a failure to include capacity credits where capacity can be deferred through purchases of QF power.

4. Requirements to wheel power for QF's to other utilities, as well as retail customers, based on embedded cost differentials.

5. Limitations on the fuels and types of generation technologies eligible for QF status, or in the alternative, vintaging purchase power rates by fuels and generation technologies.

6. Operating and efficiency standards requirements established by the FERC for cogenerators.

7. Maximum facility size for small power producers.

8. Limitations on utility ownership of QF's.

The discussion of these issues, however, fails to recognize that cogeneration realistically can drive down the cost of electricity in the long run as utilities avoid building costly powerplants. Generally, on a national average basis no present utility rate increases are attributable to cogeneration, and in fact decreasing electric rates in certain regions are directly attributable to cogeneration.

Avoided Cost Standards

The economic efficiency issues and rules governing utility purchases from QF's are reviewed in Section V. The first portion of this section includes a discussion of the evolution of the avoided cost standard. It excerpts a number of references from the large volume of testimony that was provided during the original PURPA hearings and subsequent rulemaking by the FERC. It establishes the arguments supporting the concept of full avoided costs whereby energy and capacity credits should be paid under PURPA and it describes how the "just and reasonable" standards relate to full avoided cost pricing for QF power.

The authors explore the different methods which have been used by various states to derive full avoided cost determinations, and point out that under the FERC Regulations individual states have the right to set avoided cost determinations at some level other than full avoided cost. Some states have done so pursuant to state law authority which DOE characterizes as an economically inefficient course of conduct. For this report to castigate state commissions for not deriving "correct" avoided costs is disingenuous at best. PURPA mandates that a methodology must be developed to calculate avoided costs. No single methodology can be imposed on the entire country for what is essentially a complex socio-economic, environmental and political issue.

This leads to a discussion of the variations in methodologies used in deriving full avoided cost rates. This particular section points out a fairly extensive area of inconsistency in the implementing provisions of PURPA established by the FERC. When the FERC issued its Regulations and conducted its rulemaking process, it did not define a specific method by which states could arrive at a full avoided cost calculation or determination. In an independent manner, state legislative bodies and public service commission staffs have chosen a wide variety of methods for determining the full avoided cost both for energy and for capacity. This gives rise to the argument by the authors that some states are, in fact, paying more than the highest avoided cost because of their avoided cost calculation methodologies. Many of the states referenced in the document have since engaged in their own self-corrective actions. Some states have continued relying on indigenous state statutory authority for such rates. Irrespective of either approach, the authors fail to address how their recommendations for more vigorous federal control of state ratemaking in this area squares with the Supreme Court decision in FERC v. Mississippi, (1982) upholding the constitutionality of PURPA because of its delicate balance between federal and state law.

The methods that have been identified in this study as suggested methods for avoided cost calculations, include:

1. Long-run marginal methods,

    (a) a proxy unit to be avoided, or

    (b) expansion planning approaches.

2. Short-run marginal cost methods,
    (a) single unit approaches,
    (b) incremental heat rate approaches, and
    (c) production costing approaches.
3. Purchase power approach.
4. Reverse the meter approach.
5. Differential revenue requirements approach.
6. Average incremental cost method.

Each of these methods has associated advantages and liabilities which have been thoroughly reviewed in the current literature. The methods which are identified by this document as the more accurate also require the use of sophisticated computer models and extremely detailed data on current and projected costs. These methods are generally based on variations of multi-variable linear programs which use a variety of algorithms to describe reality in mathematical terms so that this incremental cost based upon current reality can be projected into the future. It requires a very high level of sophistication to even understand how to run the computer programs much less interpret them. Many states have adopted simpler methods because of staff, computer or funding shortages and are apparently criticized by the authors for their "simplistic" approach because theoretically they "could" be offering incentives to QF's which are greater than full avoided costs. However, after all such anecdotal analysis, the document generally finds, citing DOE:

> "... most states have been setting rates for purchases of QF power which are consistent with FERC's Section 210 rules for such rate setting. [We are] concerned, however, that a few states have established rates that are higher than allowed by FERC's rules. The effect of such high rates is in essence to subsidize the QF, raise consumer rates and cause less economical generating sources to displace more economical sources. In some cases we see the potential for relatively less economical oil or natural gas cogeneration electrical generating sources to replace more economical sources powered with abundant domestic resources such as coal fired central station plants ..." (p. 5.16)

In the same set of testimony, an additional quote from DOE is provided:

> "... 'avoided cost' payments should be based upon the utility pursuing a capacity expansion plan calculated to

> minimize consumer costs over time. Payments to QFs for purchases should be calculated using the differential revenue requirements method or a similar method (i.e., difference in the present value of the utility's revenue requirements for rate making purposes, computed with and without the QF purchase) if the costs are going to be correctly calculated. If these steps are followed, [public utility commissions] will be able to avoid inadvertently subsidizing QFs." (p. 5.16)

These two quotations are cited because they represent the underlying philosophy of the subtle arguments embodied throughout this document. Followed through to its completion, the logic proceeds if any one state is, in fact, making some apparent mistake at deriving its avoided cost determinations, then all states should be subjected to a uniform national policy which will be based on some "least common denominator"-type standard for avoided cost determinations. This argument is fraught with fallacy. Each state and, in fact, specific electric utilities within each state have such different operating characteristics, based on individual company's management policies, generation mix and customer load profiles carried out over time, that there is no method for establishing a uniform policy across the United States much less within an individual state. Some states have issued very high incentive purchase rates for small power production, but not for cogeneration. Other states have supported direct subsidies through discount or economic development rates which may be no different than current PURPA incentive ratemaking.

Electric Utility Efficiency

Some electric utilities have been managed very efficiently and now enjoy competitive electric costs for their ratepayers along with a high rate of return for their investors. Other electric utilities have not been managed as well and have suffered. Their ratepayers are experiencing much higher electric rates and their shareholders have suffered losses to the value of the equity or book value in those companies. These factors, coupled with individual state regulatory policies and limitations, do more to present opportunities for QF development than any of the other factors reviewed in the marketplace. Yet, the authors ignore this critical factor. The document implies that electric utilities have been very efficient operators. They may be very efficient distributors of electricity, but their operating efficiency tends to be overstated. The maximum achievable thermal efficiency of a conventional boiler and steam turbine approaches 33% at its maximum. An examination of the average heat rate of most utilities shows that their efficiencies are closer to 30% or less. Only combined cycle units show a higher conversion efficiency of fuel to electricity. Combined cycle powerplants which reach 47% efficiency, are generally used for peaking purposes only. Therefore, if an electric utility, on a regular operating basis, is wasting 70% of the energy content of its fuel which is being consumed, and a cogenerator is using 70%-80% of the fuel value being consumed, any arguments touting the efficiency of the electric utility simply contradicts the basic facts.

Displacement of Electric Utility Capacity

The second prevailing argument in the document is that QF's might prevent electric utilities from developing future capacity which might be more efficient. This argument is unfounded and unsupported for several reasons.

Electric utility companies maintain very high operating overheads. These overhead costs are passed on to the ratepayers. Most QF developers work with much smaller staffs, with far less overhead and from that basis alone can develop electricity and deliver it at costs which will be lower in both the short- and long-term compared to electric utility costs.

Electric utilities cannot necessarily construct plants that are more efficient than cogenerators or small power producers. This is also an unsubstantiated argument because the net heat rate which is achievable from a steam turbine powerplant has an electric conversion efficiency limitation of about 33% of the BTU's consumed by the system. The types of plants which can achieve that level of efficiency are very large, baseload plants which operate at the super-critical range of temperature and pressure. These units are very costly to construct, have a history of high maintenance costs, and less than desirable reliability. These plants are also usually coal-fired plants. Plants of that nature, if they were to be sited and constructed today to meet all of the environmental requirements including limitations on sulphur dioxide emissions, would cost anywhere from $1,500 to $2,500 per KW.

Cogeneration plants, by comparison, can be built for under $1,000 per KW and achieve conversion efficiencies equal to or better than the most efficient of the coal-fired plants now in operation. Furthermore, the availability and reliability of those plants are equal to or exceed the majority of the coal-fired powerplants in operation today in the United States, whose capacity factor has decreased over the past 10 years to just 51% in 1984.

Relationships of Cogeneration to Nuclear Power

The authors also present a position that nuclear power is somehow cheaper than cogenerated power. The cost factor ignored in a nuclear powerplant is the cost of decommissioning that powerplant. Until now, government and the electric utility industry have avoided this very real cost factor. Today, however, a number of nuclear plants are beginning the process of decommissioning and it is becoming clearly evident that the disposal of high level radioactive waste may well be as costly as building the plant in the first place or more. This cost will be passed through to the ratepayers in future rate increases, and will constitute in fact, an unrecognized cost of previously consumed electricity.

On an avoided cost basis, documented cases indicate that current nuclear plants are being placed in service at 14¢ to 19¢ per Kwh nationwide with capital, O&M and related support costs representing 75% of the cost of the facility. With the current difficulty in completing existing nuclear plants, and no new plant orders since 1978, the long-term viability of nuclear power as a new supply option simply defies all logic and current facts.

Oil- and Gas-Fired Cogeneration

A final argument which is put forth in this study is that oil- and gas-fired cogeneration may, in fact, increase oil and gas consumption when it was the intent of Congress to decrease our dependency on oil and natural gas. This is an argument which serves coal interests. This argument can be refuted by showing the example of the amount of fuel that is consumed to generate electricity which is purchased by a manufacturing company plus the amount of fuel that is consumed to produce steam in a steam boiler for that same manufacturing company compared to the amount of fuel which would be consumed if all of that electricity and steam were provided by a cogeneration plant. On the most simple calculation basis, the combination of the electric utility and the conventional boiler will consume 65% more fuel than the cogeneration scenario. Cogeneration plants burn less fuel overall than electric companies and energy users (or heat users) creating energy use systems independent of each other.

Risks of Cogeneration Reliance

The authors provide some arguments to establish a basis for paying less than full avoided costs. According to this analysis, ratepayers are at a higher risk with cogeneration projects coming into their system. This argument ignores the obvious fact that a cogenerator or a small power producer builds a project at its cost and is at risk for the equity in that project. This equity investment frequently ranges from 20%-30% of the total project cost. The only way that the developer can earn a return from its project is by selling electricity to the electric utility which then resells it to its retail customers or by displacing the electric utility by selling electricity directly to an end user. Typically, in power purchase agreements between QF's and electric utilities, there is no provision for the electric company to pay for capacity if electricity is not delivered by the QF. The ratepayer is never at risk if the QF cannot provide power to the system.

In contrast, if an electric utility builds a facility which does not perform and operate up to standard, the ratepayer is at full risk for that facility because its costs become embedded in the rate base. Whether the facility produces revenue for the electric utility or not, the ratepayer pays a "reasonable" rate of return on that investment in addition to a return of that investment. This is currently the case for the 75,000 MW of idle oil-fired generation capacity nationwide which has functionally been dormant since 1981. If currently used that oil-fired capacity would increase oil imports by $15 billion with attendant consequences on our current balance of trade deficit.

State public service commissions are starting to recognize that the ratepayer is at greater risk for the decisions of the electric utility industry than for contracts with QF's who only recover their investment if their assets are producing assets. The dimension of that ratepayer risk is directly measurable by the amounts of tax normalization, construction work in progress, AFUDC, plant decommissioning, and amortization of plant costs associated with such decisions. The secondary risks relate to the impact of such decisions on the utility's cost of capital, bond ratings, and stock values which are impacted by such decisions. Ratepayers are not exposed to the risks of a Marble Hill, or a Midland nuclear powerplant, or Washington Public Power cancelled nuclear powerplants when they contract through their electric utilities for the power generated by QF's.

Displacement of Coal-Fired Generation

The authors specifically cite cases in California where the DOE argued that an 1800 megawatt coal-fired facility was cancelled by Pacific Gas & Electric and Southern California Edison Companies because of the large amount of oil- and gas-fired cogeneration which had been contracted for by those companies. (p. 5.22, 5.25)

In a study conducted by Hagler-Bailly in 1982, DOE claimed that the cost of a new baseload coal-fired powerplant would be less than the cost of the power provided by cogeneration facilities. DOE's use of this study was widely criticized by Hagler-Bailly as an over-extension of its findings, and independently challenged by Congressional and private sources, such as the Cogeneration Coalition.

The arguments in the Hagler-Bailly study reference case are based on 1982 economics. At that time, oil and gas prices were escalating. In 1986, oil and gas prices have fallen sharply. This entire reference to support arguments regarding oil- and gas-fired cogeneration and the displacement of coal-fired generation has now become an invalid reference and is somewhat disingenuous.

Consumer Equity with Full Avoided Costs

A further argument is made for the consumer equity concerns under the full avoided cost standard in PURPA. The authors state that there is a perceived inequity if the ratepayers are not permitted to share in the economic benefits of cogeneration and small power production. This represents an old argument presented in 1980 by the electric utility industry which has been specifically rejected by the FERC, numerous state public service commissions, and the Supreme Court.

The full avoided cost standard was established to encourage the development of cogeneration which is a substantially more efficient means of generating electricity and utilizing heat than if each of those functions are performed separately. The developer of a cogeneration project is at full risk until its project begins to produce electricity and steam. If the system fails during operation, the developer continues to bear that risk. This risk management scenario needs to be comparatively assessed. Compare that risk to the risk that is taken by the ratepayer for nuclear accidents, such as Three Mile Island where he must also pay for the cleanup of that plant. Or compare the risk that the ratepayer assumes for plant decommissioning and related costs once a nuclear unit is taken out of service. Or consider the simpler risk of scheduled or unscheduled maintenance. Under these circumstances, the risk argument of the authors regarding QF power is unsupportable.

Some additional arguments are presented supporting contract reopener provisions which would provide for lower purchase power rates based on changing economic circumstances. Contract reopeners, under any circumstances, are untenable because they create a new arena of uncertainties impeding the development of a financing package for a cogeneration plant. Such contract terms are widely unacceptable in the financial community, and are used as a negotiation tool by electric utilities. Contract reopeners allow for a great deal of unknown future risk impeding the fuller development of cogeneration potential, and are inconsistent with the requirements of the FERC Regulations. Just as electric utilities cannot afford re-examination of decisions reflecting committed capital, QF's should not be subjected to disparate treatment.

Competitive bidding for available capacity credits among QF's is also discussed. A number of arguments are advanced presenting several conflicting positions. It is an issue that has been handled differently by several states, such as Maine, Massachusetts, Oklahoma, Connecticut and Texas.

As a threshold matter, there is a real fallacy in comparing QF's to electric utilities from a risk perspective to the ratepayer as previously discussed. Moreover, PURPA envisioned QF's competing with electric utilities to provide generation capacity, and not necessarily among themselves. In some instances, competitive bidding could be used as an attack against the full avoided cost principle. However, competitive bidding could also be viewed as a means of creating an orderly market, when QF capacity exceeds demands, by following the pattern devised in Maine where certain blocks of capacity were evaluated at different avoided cost rates depending upon the satisfaction of the future power requirements for that particular block of capacity.

Rates in Excess of Full Avoided Costs

Section VI of the document relates to requirements to pay for purchases from QF's at rates which exceed full avoided costs. The tone set by the authors improperly creates the impression that such rates are more prevalent than is the case. As the document discloses, citing DOE:

> "... we have noticed some cases where PUC's have set rates purportedly at the full avoided cost level but that in fact exceed the level because utility avoided costs have been incorrectly calculated. These rates, insofar as they exceed the full avoided cost level, create a subsidization of QFs not authorized by Section 210 of PURPA." (p. 6.1)

This particular argument clouds key issues and centers around the allegation that utility avoided costs have been incorrectly calculated.

There is not one concrete example provided by the authors which shows how an electric utility's full avoided cost should be calculated or where the avoided cost exceeded the true avoided cost. There is a table provided showing where, in California, the energy cost could have exceeded the marginal cost of the electric utility, but it says nothing of the comparison of capacity costs on a levelized basis.

In instances where electric utilities sought adjustments in full avoided cost rates for defensible reasons, such mid-stream adjustments were provided in California, Texas, Idaho, Montana, Colorado and New York.

Timing of PURPA Rate Review

This study and upcoming Congressional oversight hearings are being conducted to review the effects of PURPA on the development of cogeneration and small power production in relationship to the expectations that were presented back in 1978 when the legislation was enacted. Unfortunately, from 1978 to 1983, very little happened in relationship to the development of small power production and cogeneration because the electric utility industry kept various issues in the courts, discouraging cogeneration and small power production until a Supreme Court decision was finally rendered in 1983 in the American Electric Power case. In this full eight year period, PURPA has been subjected to three Supreme Court challenges and over a dozen state court challenges by electric utilities.

In fact, the whole cogeneration and small power production industry did not start to fully develop until after the Supreme Court decision. It generally takes 24-36 months to develop a cogeneration project. Thus, the first real impact of PURPA could not be felt before 1985. In fact, 1986 is the first full year in which we can see what the true impact of PURPA is likely to have for the future. On this basis, this report is somewhat premature.

It seems inappropriate to utilize the data from less than one full year of operations to evaluate the effects of the legislation that was passed in 1978. A number of cases support the fact that, in general, the principle of cogeneration and small power production has been beneficial to the country rather than harmful. It has added new capacity in areas that needed new capacity, and it has done so in a timeframe and at an efficiency level far better than that which could have been achieved by the electric utility industry. Moreover, it has provided a significant contribution to breaking the grip of the OPEC cartel on U.S. energy supplies.

The electric utility industry is gradually losing its monopoly power over generation, and it is constantly seeking new ways to thwart the basic intent of PURPA as it was presented in 1978. This delay and obfuscation is also charged to ratepayers as a cost of doing business to ensure that electric power generation will not become a competitive business for the future.

The best example to demonstrate that is the new thrust by the electric utility industry to be able to own more than 50% of a cogeneration project so that, in fact, they can dominate cogeneration development and thereby discourage competition in their marketplace. This position is unsupportable as a matter of policy since the electric utility would never want more than a 50% equity interest to ensure the investment was kept off balance sheets. Moreover, even with a 50% equity interest opportunity since 1978, electric utilities have accounted for less than 1% nationwide of all QF project applications filed at the FERC in almost eight years.

Enforcement of Utility Obligations Under PURPA

Various states have acted to enforce utility obligations under the PURPA regulations. Enforcement has generally been achieved by lowering the allowed rate of return earned by the uncooperative electric utilities. California, Idaho and Maine have used their statutory authority to enforce compliance.

The FERC has avoided exercising its authority to enforce its rules, relying instead on the states to police these issues. The evidence in the document clearly illustrates that FERC has not been active and responsible in enforcing PURPA provisions which leaves a large area of uncertainty for QF's. The document makes a number of effective observations and recommendations regarding FERC enforcement policy for the future. The Coalition endorses those recommendations and urges the Commission to assume a more vigorous role not necessarily through litigation (which should not be foreclosed) but through policy statements, guidelines, or notices of inquiry on specific issues.

Transmission Service and Pricing for QF's

The report provides a concise analysis of a number of key issues on wheeling. It clearly points out the conflicting roles between state and federal jurisdiction over this issue. Supporters of wheeling have cited the FERC voluntary wheeling position in its Regulations that utilities must purchase power from remote QF's, if the power is wheeled voluntarily by the QF's local electric utility. FERC did not make wheeling mandatory. Certain state public utility commissions have issued mandatory rules under indigenous state laws. Alternatives to mandatory rules by state public utility commissions have also been reviewed.

The report casts the mandatory wheeling issue in terms of a quid pro quo for other aspects of the PURPA Regulations: "While mandatory wheeling for QFs would appear to be consistent with the objective of promoting competition in bulk power supply, there are a number of reasons why such a mandate alone -- in the absence of several other important changes in the current utility regulatory scheme -- may not be in the public interest." (p. 8.14) While offering no rationale or support for its conclusions, the authors do not reconcile how wheeling would not foster the economic efficiency goals sought through the entire document. This failure to fully support wheeling as a tool to address the perceived problems raised by PURPA implementation is counterintuitive and irreconcilable with other elements of the document's critique of PURPA implementation.

The utility arguments against mandatory wheeling pose several key issues which need further evaluation. The authors maintain that QF's should not be entitled to both guaranteed purchases by the electric utility at full avoided costs and guaranteed access to other purchasers through mandatory wheeling. It gives no clear cut argument why not. Further, it ignores the fact that if greater efficiency could be achieved by a QF why should a QF be denied the opportunity to deliver electricity where it can be used more effectively to avoid excess capacity concerns or other issues related to PURPA implementation? Another question that is raised is that of a QF wheeling to another one of its own facilities. There may be arguments with some underlying validity which merit individual evaluation at the state level. Existing transmission systems were not necessarily designed to accommodate third party wheeling. At the same time, this ignores the interconnected nature of electric powerpools, and their sophistication in moving power through the grid. Where adequate transmission capacity does not exist (as proven by the electric utility), then transmission access may be more limited subject to construction of additional capacity for the future.

Further discussion centers around the fact that with wheeling, especially in Texas where FERC does not have jurisdiction because the Texas Power Pool is not connected to the interstate grid, QF capacity is being wheeled within the state and in fact deferring the construction of powerplant capacity for companies outside of the Houston Lighting and Power Service (HL&P) area. At the same time, a large amount of capacity is being built in the HL&P service area. Not only has HL&P deferred a new powerplant, but several utilities have been denied the right to build plants by the Texas Commission because capacity is available under the wheeling provisions in Texas, and utilities can avoid building new power plants if they buy capacity from QF's in the HL&P service territory. This experience and related efficiencies would appear to support more widespread promotion by DOE of wheeling for QF power under existing authorities. Yet, the document falls short of such an endorsement inexplicably and inconsistently with the priorities expressed elsewhere therein.

MJZ/20

ATTACHMENT 11

POTENTIAL DETRIMENTAL EFFECTS OF COGENERATION DEVELOPMENT ON UTILITY COSTS: A PRELIMINARY ASSESSMENT

Contract No. DE-AC01-84CE40646

HBC Reference No. RA86-3009

Prepared for:
U.S. Department of Energy
Office of Industrial Programs
Washington, DC

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February 1986

POTENTIAL DETRIMENTAL EFFECTS OF COGENERATION DEVELOPMENT ON UTILITY COSTS: A PRELIMINARY ASSESSMENT

The Office of Industrial Programs (OIP) of the U.S. Department of Energy (DOE) is responsible for the research and development of technologies aimed at improving the energy efficiency of the U.S. industrial sector. To reach this goal, OIP supports the research and development of advanced industrial cogeneration systems. A critical factor in the successful deployment of advanced cogeneration systems is the ability to sell the electric power coproduced by these systems at economically attractive prices. However, there have been assertions that there are instances where cogeneration electricity sales to utilities may be driving up utility costs. The extent and severity to which these instances exist, and the likelihood that they will continue into the future, could have a direct effect on the future role of cogeneration.

In targeting its programmatic objectives for advanced cogeneration technologies, OIP determined that it needed a better understanding of the conditions and likelihood where the widespread deployment of industrial cogeneration could detrimentally affect utility costs. OIP contracted with Hagler, Bailly & Company to (a) identify those conditions where industrial cogenerators selling electricity to a utility could detrimentally affect the utility's average cost of electricity, and (b) determine whether these distortions in utilities' average cost of electricity exist.

BACKGROUND

The National Energy Act (NEA) of 1978, consisting of four specific laws, was a major milestone for the cogeneration industry, encouraging the construction and use of cogeneration facilities as a means of promoting the conservation of nonrenewable resources. Under the Public Utility Regulatory Policies Act (PURPA), one of the laws embraced by the NEA, the Federal Energy Regulatory Commission (FERC) adopted rules that removed many of the obstacles standing in the way of full exploitation of the country's cogeneration potential.

POTENTIAL DETRIMENTAL EFFECTS OF COGENERATION DEVELOPMENT ON UTILITY COSTS: A PRELIMINARY ASSESSMENT

PURPA and its attendant rules require electric utilities to purchase electricity generated by qualifying cogeneration facilities at prices deemed equivalent to the costs avoided by the electric utility by not having to generate and deliver the electricity produced by the cogenerator. Electric utilities are also prohibited from rate discrimination in the supply or purchase of electric power, and are required to interconnect with qualifying cogeneration facilities. In addition, PURPA exempts cogenerators from the many regulatory requirements peculiar to electric utilities.

Since March 1980, when the majority of FERC regulations governing cogeneration went into effect, the development of cogeneration projects has been dramatic. As of September 30, 1985, the number of cogeneration and small power generation projects (existing and proposed) seeking "qualification" under PURPA reached nearly 2,000 representing roughly 30,000 MW.

The prospects for the future continue to be bright for industrial cogeneration, with expectation of nearly 500 applications to FERC for certification and notifications expected annually for the near term. In addition, market studies sponsored by DOE and others conclude that the market development of industrial cogeneration facilities could reach between 20,000 MW and 50,000 MW by the end of the century. By the year 2000, cogenerated power may account for more than 15 percent of the U.S. electrical capacity, which is more than twice that estimated to exist currently.

Since the implementation of the PURPA and its attendant federal regulations, state regulatory commissions and electric utilities have attempted to determine acceptable procedures for pricing mandatory utility purchases of electricity generated by "qualified" cogenerators and small power producers (QFs). With some exceptions, state commissions have set prices at avoided costs, defined by FERC as incremental costs to an electric utility of electric energy or capacity or both, which -- but for the purchase from the qualifying facility or qualifying facilities -- such utility would generate for itself or purchase from another source.*

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*Code of Federal Regulations, Title 18, Chapter 1, Part 292, Subpart A, §292.101(b)(6).

PURPA further provides that the purchase prices be just and reasonable to the customers of the electric utility, and that the utility shall not discriminate against qualifying cogenerators or small power producers. PURPA does not, however, describe how to determine "just and reasonable" prices for purchased electricity.

PURPA does not prevent a utility and a QF from negotiating prices for the purchase of QF-generated power. If the parties cannot agree on an appropriate price, most state utility commissions adjudicate the price. Because it would be cumbersome and time-consuming to adjudicate such prices on a case-by-case basis, many utility commissions have made an effort both to develop a generic method by which to compute avoided cost, and to apply the selected method to service territories within their jurisdictions.

The efforts of the state commissions have been hampered by the complexity of avoided cost determinations and the inevitable use of the courts by some parties seeking price adjudication through litigation. As a result, these efforts continue through the present, despite the fact that it has been 6 years since the promulgation of federal regulations by FERC.

APPROACH

Hagler, Bailly & Company conducted its study of the potential detrimental effects of cogeneration on average utility costs by selecting 13 utilities for review and assessment:

- Boston Edison Company
- Central Maine Power Company
- Central Power & Light Company
- Consolidated Edison Company of New York
- Commonwealth Edison Company of Illinois
- Florida Power & Light Company
- Gulf States Utilities Company
- Houston Lighting & Power Company
- Niagara Mohawk Power Corporation
- Pacific Gas & Electric Company
- San Diego Gas & Electric Company
- Southern California Edison Company
- Texas Utilities Electric Company.

These utilities were selected on the basis of three criteria: (1) relatively high level of cogeneration (and small power generation) activity existing in service territory, (2) relatively high level of "buyback rates" (i.e., purchase prices) currently offered to cogenerators and small power generators, and (3) regional dispersion; that is, the selected electric utilities should represent a large number of regions of the country. The list of 13 utilities includes the major electric utilities of Texas and California, with other utilities representing the Northeast, Southeast, and Midwest. It was felt that if detrimental effects from cogeneration existed and could be identified, these 13 utilities offered the best starting point.

For each of the 13 utilities, pertinent data were obtained from 1984 operating statistics (see Exhibit 1):

- Electricity rates: average electricity rates paid by industrial customers and average electricity rates paid by all customers
- Electricity costs: costs of generating electricity; costs of purchasing electricity from cogenerators (and small power generators); average costs of all purchased electricity; overall average costs of electricity from all sources
- Amounts of electricity: generated; purchased from industrial cogenerators (and small power generators); purchased from all sources
- Electric supply capability: fuel mix by electricity generated.

Finally, detailed discussions were held with representatives of each selected electric utility and state agency responsible for regulating the transactions between the selected utilities and cogenerators (and small power generators) located in the utilities' service territories. These discussions focused principally on the procedures used in establishing buyback rates, the relationship between the utilities' avoided costs and buyback rates adopted, and the mechanisms used in dealing with disparities between the utilities' avoided costs and buyback rates.

Exhibit 1

1984 Operating Statistics for Selected Utilities

Utility	Electricity rates (¢/kwh)		Electricity costs (¢/kwh)				Source of electricity (%)			Self-generated electricity by fuel type (%)				
	Industrial	All customers	Generated	Purchased	Industrial cogeneration	Average	Generated	Purchased	Industrial cogeneration	Oil	Gas	Coal	Nuclear	Hydropower
Boston Edison Company	9.3	10.6	5.9	5.1	—	5.6	61	39	Neg.	75	25	0[1]	0[2]	0
Central Maine Power Company[3,4,5]	4.9	6.3	3.3	4.0	5.8	3.8	35	65	11.0	51	0	0	0	49
Central Power & Light Company	5.5	6.4	3.6	2.5	3.2	3.6	98	2	0.4	—75—		25	0	0
Consolidated Edison Company of New York	13.6	13.6	6.1	4.0	—	5.3	60	40	0.0	82	1	0	17	0
Commonwealth Edison Company of Illinois	6.1[6]	7.8	2.8	2.7	—	2.8	95	5	0.0	3	1	42	54	0
Florida Power & Light Company	6.5	8.0	3.3	4.2	4.0	3.5	79	21	0.5	33	27	0	40	0
Gulf States Utilities Company	3.6	4.7	1.6[7]	3.0	2.6	2.1	78	22	0.1	—89—		11	0	0
Houston Lighting & Power Company	5.1	6.2	3.4	4.9	4.6	3.6	84	16	15.0	0	70	30	0	0
Niagara Mohawk Power Corporation	3.9	5.8	2.7	2.0	4.6	2.4	52	48	0.0	—28—		37	17	18
Pacific Gas & Electric Company	6.9	7.2	4.3	2.9	8.1	3.8	65	35	3.8	—32—		0	15[8]	53
San Diego Gas & Electric Company	12.0[9]	11.7	6.4	3.4	6.2	5.2	60	40	1.4	15	59	0	26	0
Southern California Edison Company	7.5	7.6	4.2	2.2	5.9[10]	3.5	62	38	1.9[10]	1	37	33	16	13
Texas Utilities Electric Company	4.4	5.7	2.8	—	2.3	2.8	99	1	0.3	0	68[11]	32[12]	0	0

[1] Conversions in progress.

[2] Jointly owned.

[3] Electricity costs include wind.

[4] Sources of electricity include small power.

[5] Power from Maine Yankee not included.

[6] Large commercial and industrial.

[7] Old gas contract expired on January 1, 1985.

[8] Geothermal.

[9] Including commercial.

[10] Including renewable.

[11] Lignite.

[12] Including oil.

Electricity rates depicted are annual average prices paid by customers and consist of a profit and all allowed costs, including operating, maintenance, depreciation, interest, and taxes incurred in the generation and/or purchase, transmission, and distribution of electricity for customer use. Electricity costs depicted are the annual operating and maintenance costs incurred in the production of electricity (i.e., generated and purchased).

SOURCES: Annual reports; 10-Ks; The P.U.R. Analysis of Investor-Owned Electric and Gas Utilities, 1985 edition; Uniform Statistical Reports — Year Ended December 31, 1984.

POTENTIAL DETRIMENTAL EFFECTS OF COGENERATION DEVELOPMENT ON UTILITY COSTS: A PRELIMINARY ASSESSMENT

FINDINGS

Of the 13 selected utilities, only 10 purchased electricity from cogenerators (and small power generators). As shown in Exhibit 1, Boston Edison Company, Consolidated Edison Company of New York, and Commonwealth Edison Company of Illinois purchased either negligible amounts of electricity or none at all from cogenerators during 1984, and therefore were eliminated from further investigation.

Exhibits 2 through 11 depict the cost structures of the electric utilities selected for detailed investigation. The data presented for each utility in 1984 are derived exclusively from the Uniform Statistical Reports -- Year Ended December 31, 1984. In using this information, the following clarifications and qualifications must be acknowledged:

- Based on discussions with utility representatives, the self-generation costs displayed include only fuel and operating and maintenance costs for generation. Depending on the accounting procedures used and the type and age profile of generation capacity (e.g., nuclear, hydro, coal) possessed by each utility, the increase in average costs of self-generation by fuel type owing to capital changes could range from negligible to nearly twice that depicted.

- The sources of electricity depicted for each utility in the following exhibits are those from which the utility received more than 0.1 percent of its electric energy in 1984. That is, some sources of electricity have been omitted if their individual contribution is minimal -- less than 0.1 percent.

- "Industrial cogeneration" is used to embrace purchases of electricity from all nonutility sources. The Uniform Statistical Reports classify these purchases from "industrial sources" unless otherwise noted. Discussions with representatives of the selected utilities indicate that this category consists of purchases from cogenerators, small power generators, and other independent power producers, when appropriate. Although it could not be verified during this assessment, there is the possibility that some purchases from the "public agency" category may

Exhibit 2

Central Maine Power
(Electricity Supply Cost Structure: 1984)

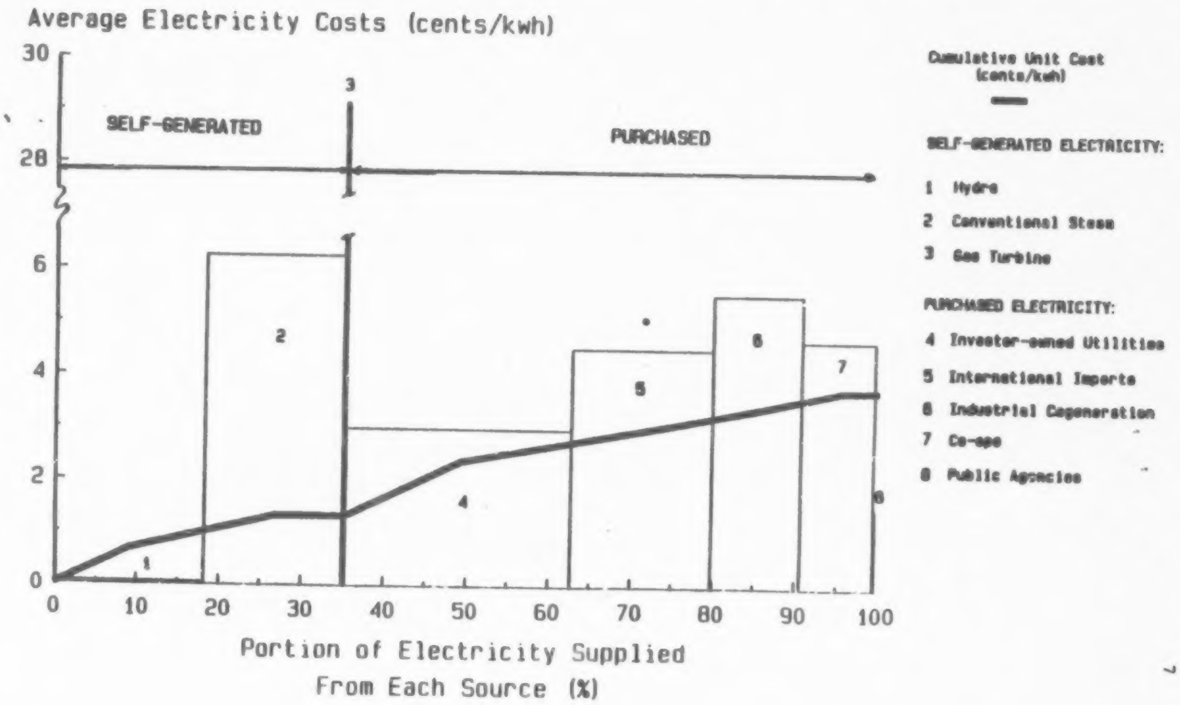
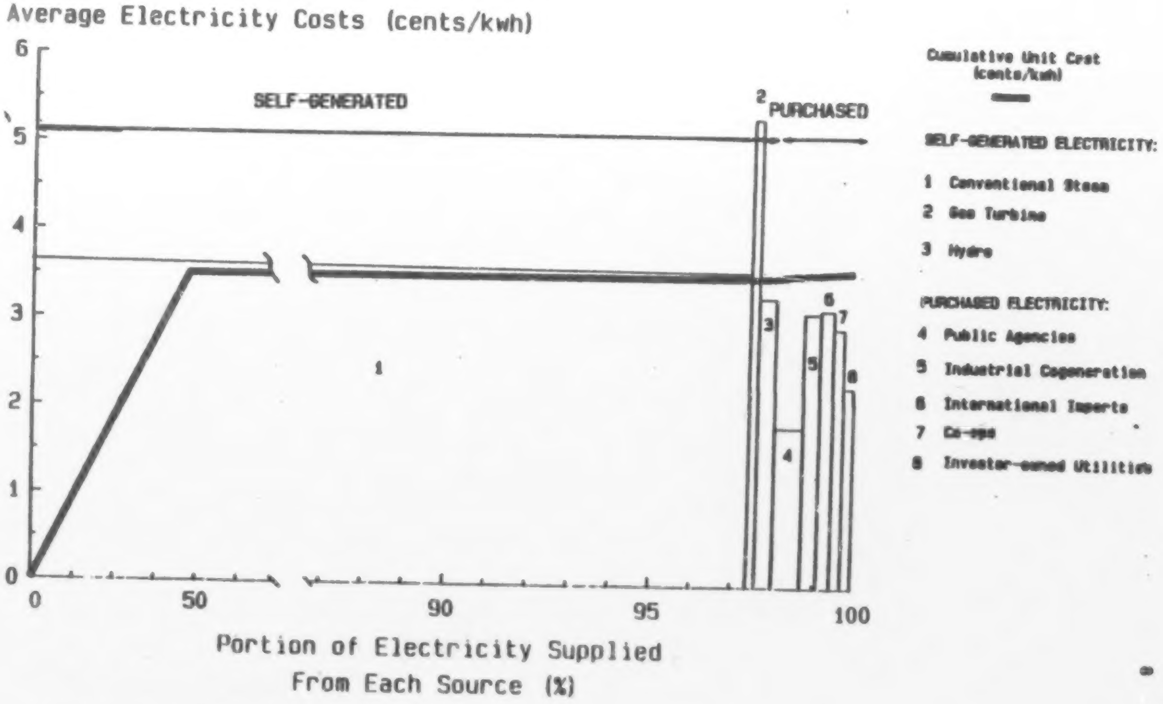


Exhibit 3

Central Power & Light
(Electricity Supply Cost Structure: 1984)



Note: Excludes wheeling losses

Exhibit 4

Florida Power & Light
(Electricity Supply Cost Structure: 1984)

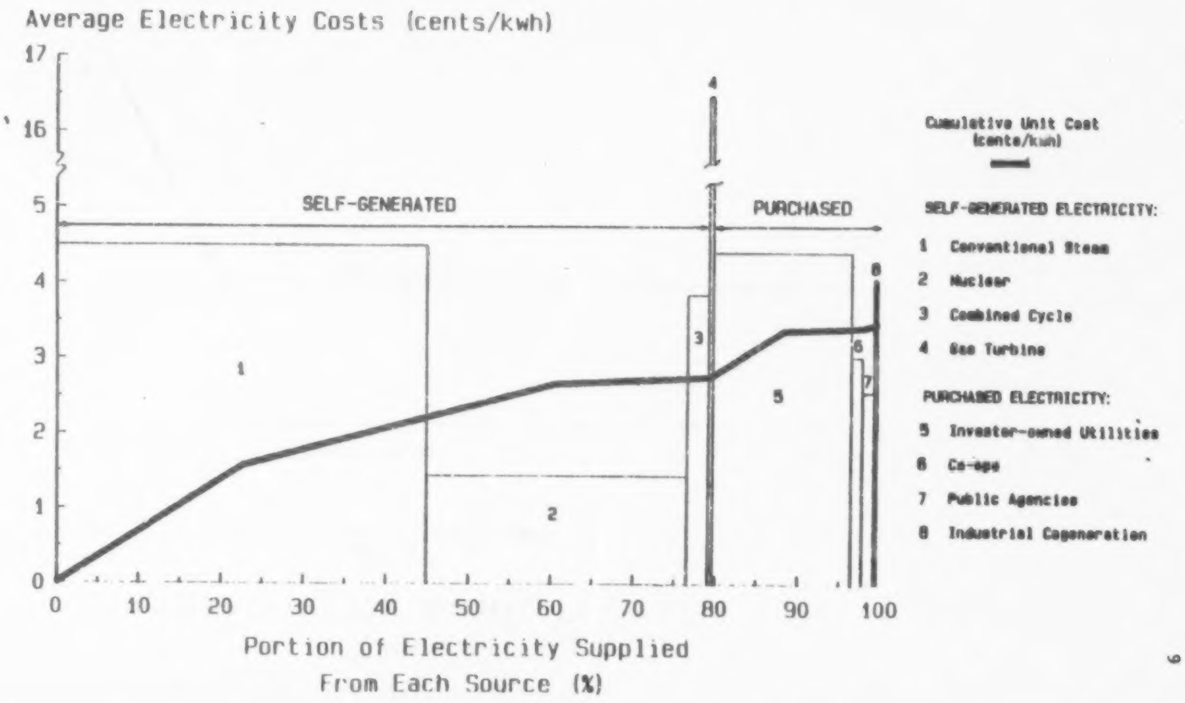


Exhibit 5

Gulf States Utilities
(Electricity Supply Cost Structure: 1984)

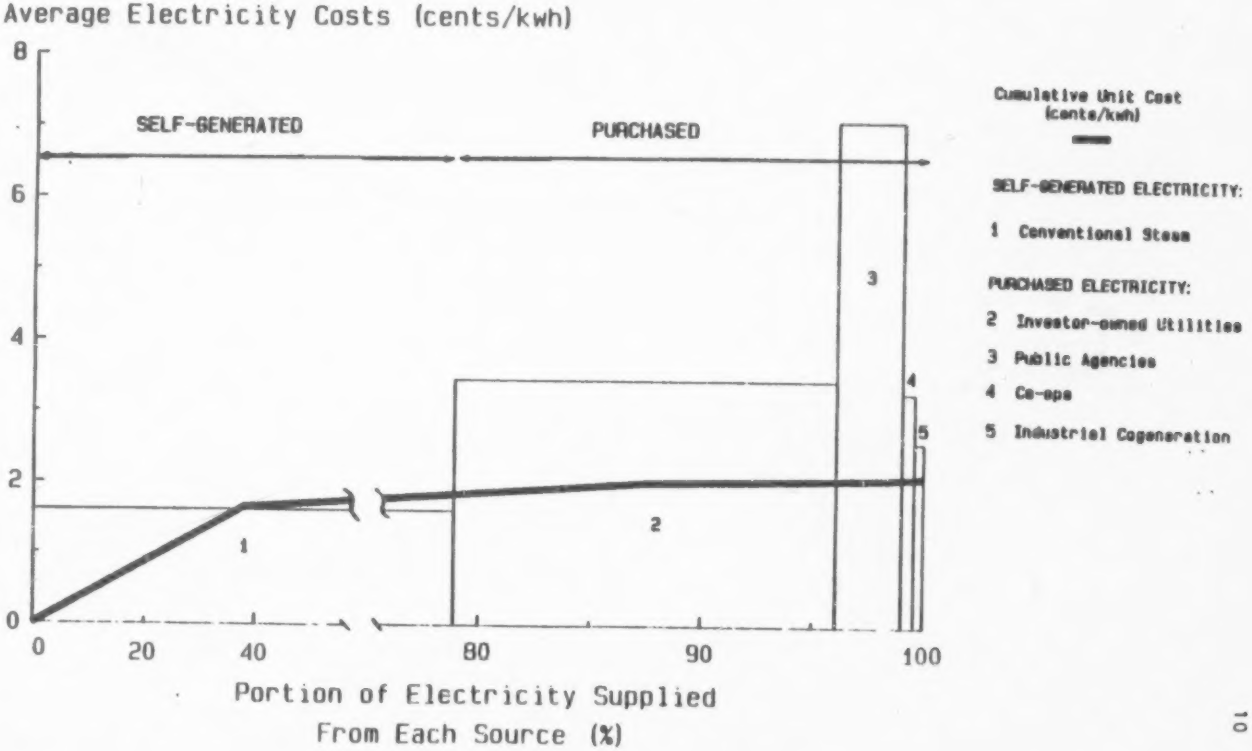


Exhibit 6

Houston Lighting & Power
(Electricity Supply Cost Structure: 1984)

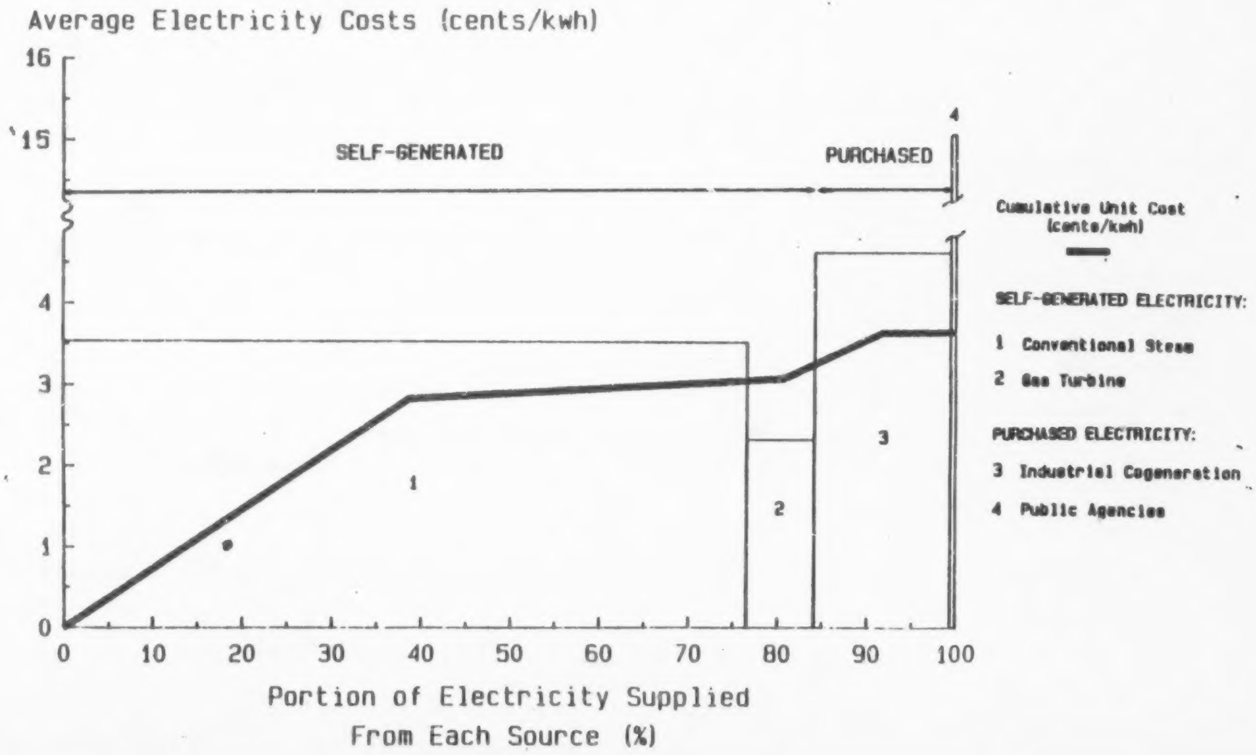


Exhibit 7

Niagara Mohawk Power
(Electricity Supply Cost Structure: 1984)

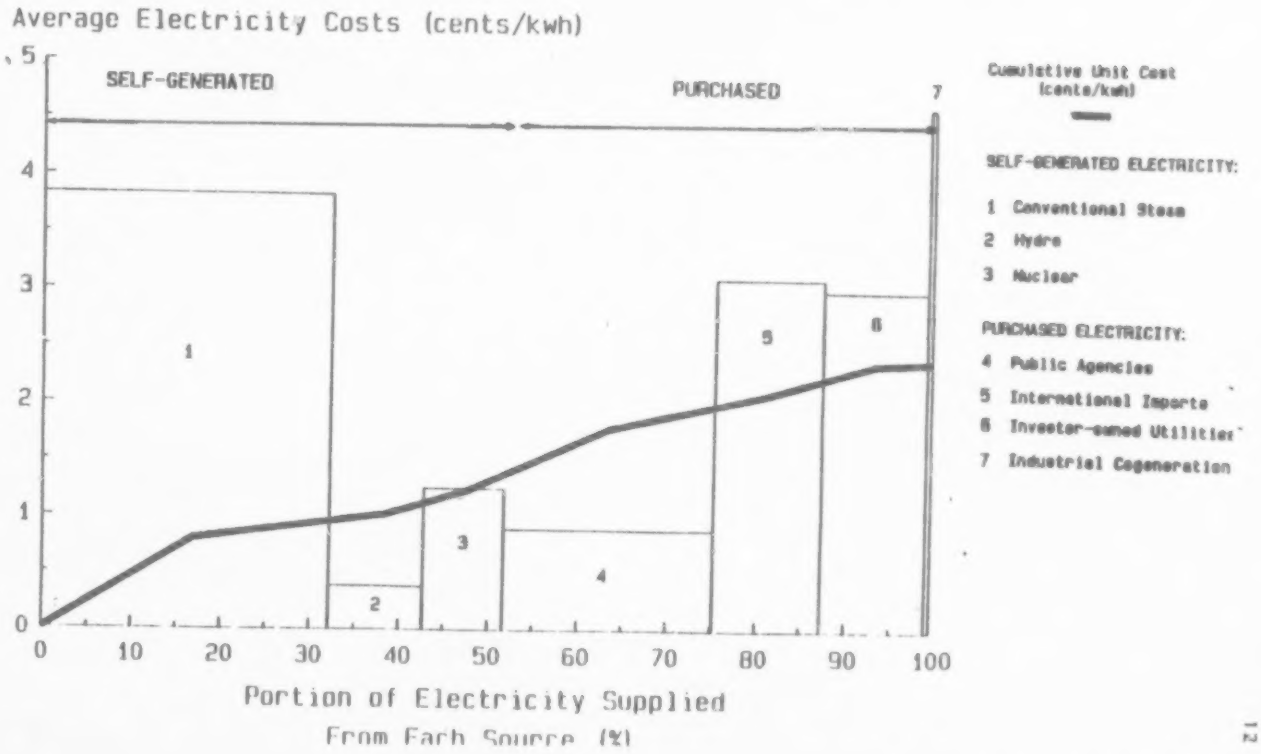
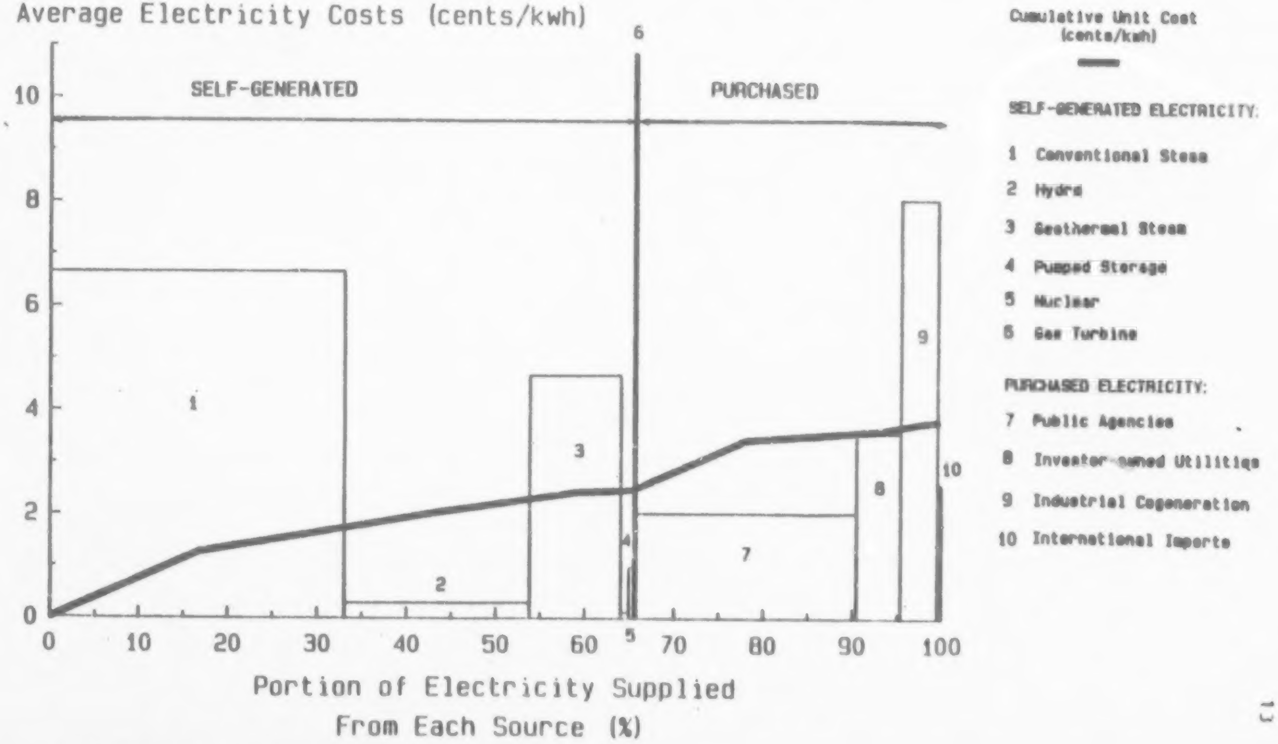


Exhibit 8

Pacific Gas & Electric
(Electricity Supply Cost Structure: 1984)



Note: Excludes electricity use in pumped storage

Exhibit 9

San Diego Gas & Electric
(Electricity Supply Cost Structure: 1984)

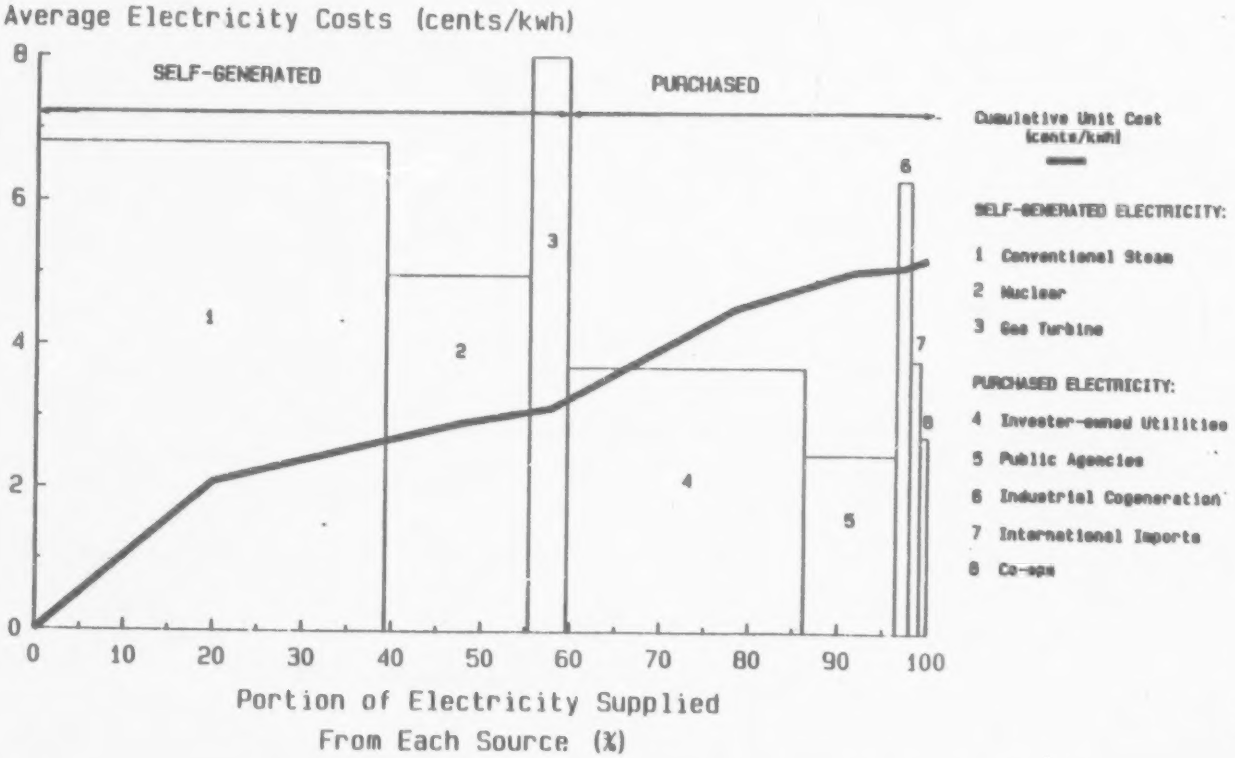


Exhibit 10

Southern California Edison
(Electricity Supply Cost Structure: 1984)

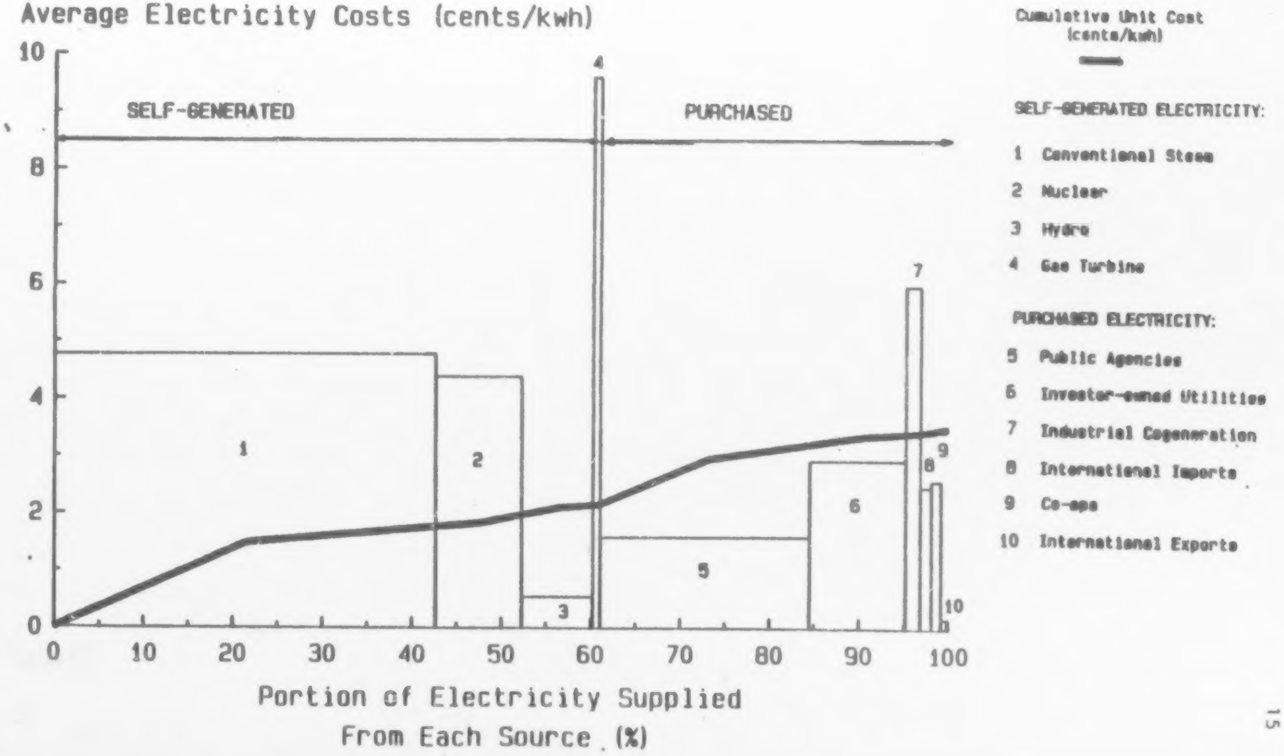
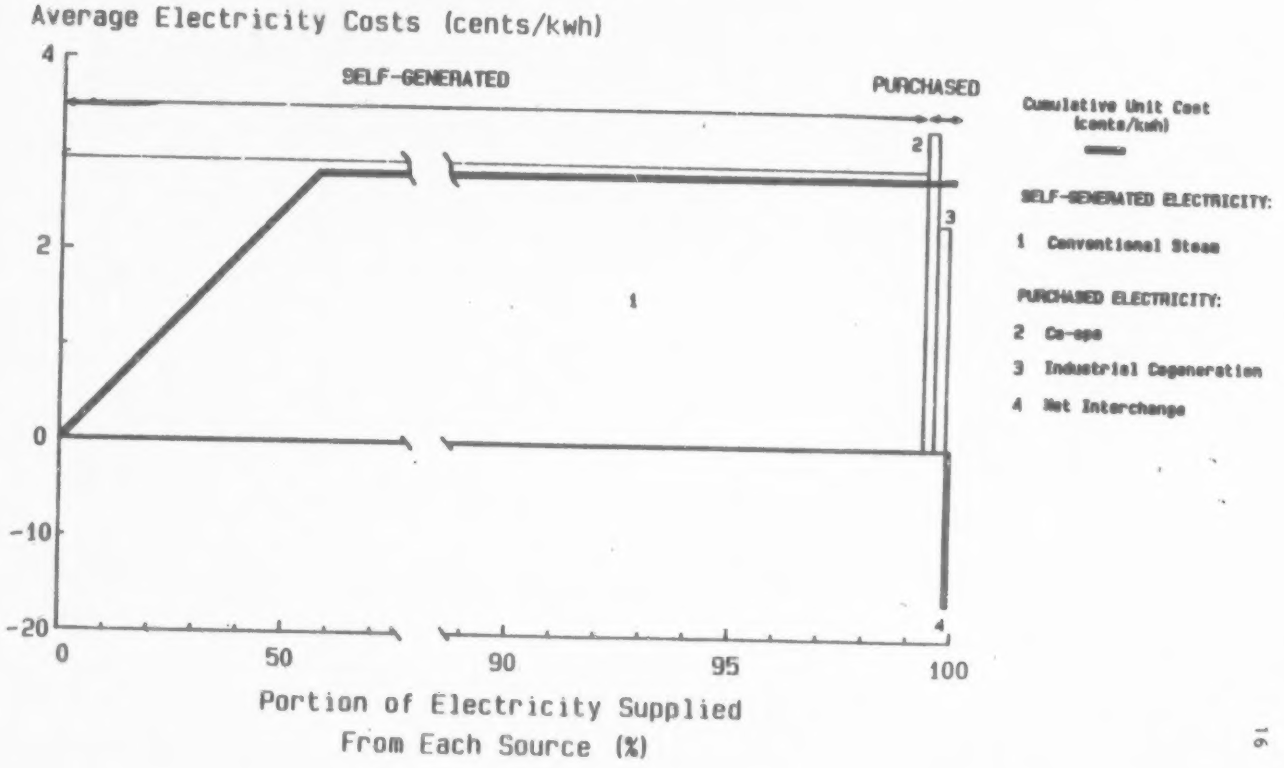


Exhibit 11

Texas Utilities Electric
(Electricity Supply Cost Structure: 1984)



actually be produced by cogeneration and small power generation facilities.

Based on the data compiled for each remaining selected utility, several important findings emerge:

- Only three utilities purchased cogenerated electricity at a price lower than the average price paid for all purchased electricity. During 1984, Florida Power & Light Company (FP&L) paid 2 percent less, Houston Lighting & Power Company (HL&P) paid 6 percent less, and Gulf States Utilities (GSU) paid 33 percent less for each kWh purchased from cogenerators than the average price they each paid for all purchased electricity.

- However, only one utility purchased cogenerated electricity at a price lower than the total average cost of all electricity -- purchased and self-generated. Of the 10 electric utilities purchasing cogenerated electricity during 1984, Texas Utilities Electric Company (TUEC) purchased cogenerated electricity at a price nearly 20 percent less than the total average cost of electricity from all sources.

- In addition to TUEC, only Central Power & Light Company (CP&L) and San Diego Gas & Electric Company (SDG&E) purchased cogenerated electricity at prices lower than their respective average kWh costs for self-generation. During 1984, SDG&E paid 2 percent less, CP&L paid 11 percent less, and TUEC paid nearly 20 percent less for each kWh purchased from cogenerators than the costs they each incurred for self-generated electricity.

- Only three electric utilities purchased more than 3 percent of their total electricity supply from cogenerators (and small power generators). Specifically, during 1984 CMP purchased 11 percent, HL&P purchased 15 percent, and PG&E purchased nearly 4 percent of their total electricity supply from cogenerators (and small power generators).

The above findings are dictated primarily, if not exclusively, by the regulatory and business environment of each utility:

- **California**. Of the 10 utilities selected for this analysis, three are major utilities located in California: PG&E, SDG&E, and Southern California Edison Company (SCE). All three purchased electricity from cogenerators (and small power generators) at prices either near or exceeding the cost of utility self-generated electricity. A contributing factor to the relatively high payments for cogenerated electricity was the adoption of firm purchase price schedules as part of long-term contracts between cogenerators and California electric utilities. For example, Standard Offer No. 4 in California was established to set guaranteed buyback rates for a 10-year period as part of firm contracts. Because these firm rates were based on 1982 energy price forecasts, which projected continued increases in fuel prices, discussions with representatives of the California Public Utility Commission and utilities located in California suggest that Standard Offer No. 4 overestimated avoided utility fuel costs, which may have resulted in firm buyback rates that may have been too high (i.e., increased the average costs of each utility). For example, discussions with SCE suggest that the current avoided energy cost is about $0.042/kWh, while cogenerators operating under Standard Offer No. 4 would be paid at a purchase price of approximately $0.06/kWh.

  To date, an estimated 10,000 MW of cogeneration (and small power generation) capacity has been signed up using Standard Offer No. 4 (out of approximately 15,000 MW total signed up under all contract alternatives in California), including roughly 5,300 MW out of 8,000 MW for PG&E, 235 MW out of 355 MW for SDG&E, and 4,000 MW out of 6,500 MW for SCE.

- **Florida**. In contrast to PG&E, SCE, and SDG&E, FP&L has no firm-price contracts with cogenerators (and small power generators), but instead computes avoided energy costs hourly. Based on discussions with FP&L, FP&L pays cogenerators (and small power generators) 100 percent of its avoided energy costs and pays capacity credits according to terms and conditions established by the Florida Public Servic Commission. Accordingly, FP&L concludes that there is no variance between actual avoided costs and buyback rates.

- Maine. CMP purchased a greater portion of its electricity supply than any other utility studied in this assignment. In addition, in 1984 CMP was second only to HL&P in the portion of its electricity purchased from cogenerators (and small power generators). Based on discussions with CMP, this portion is likely to increase from 11 percent in 1984 to 20 percent in 1988. This strategy is designed to offset the heavy dependence on electricity generated from oil (roughly 20 percent) and electricity purchased from Canada (roughly 25 percent).

  To date, CMP has been successful in negotiating purchase agreements with cogenerators (and small power generators) at purchased power prices less than the calculated avoided cost for CMP. The basis for calculating avoided costs, and soliciting bids from and negotiating contracts with cogenerators (and small power generators), are capacity increments of 50 MW. This bidding procedure has resulted in negotiated purchase prices ranging from 70 percent to 80 percent of projected avoided energy and capacity costs. However, representatives of CMP believe that with recent reductions in oil prices, the negotiated prices for electricity purchased from cogenerators (and small power generators) are nearly equal to the actual avoided costs of CMP.

- New York. Although NMP purchased less than 1 percent of its total electricity supply from cogenerators in 1984, the purchase price paid to cogenerators exceeded the average price paid for all purchased electricity by nearly 100 percent. A principal factor in determining all buyback rates in New York is the "floor" of $0.06/kWh established by the New York state legislature several years ago. The New York Public Service Commission formulated conditions and terms for long-term contracts between NMP and cogenerators (and small power generators) in the fall of 1984. NMP has contended that these buyback rate schedules were not intended to be used as part of "standard offers," but only represent guidelines for negotiations between NMP and cogenerators. Because of recent reductions in oil prices, a primary fuel of NMP and other investor-owned New York utilities, the New York Public Service Commission initiated an action in the summer of 1985 to change the method used in calculating the avoided costs of utilities in New York, resulting in reducing the buyback rates received by cogenerators (and small power generators). In addition, commission and utility representatives indicated that many of the existing contracts between cogenerators and New York utilities have mechanisms for adjusting purchase prices to reflect actual avoided costs.

- Texas. Four of the 10 electric utilities studied in detail are located in Texas. The amount of cogenerated electricity purchased in 1984 as a portion of total electricity supplied varied widely among the four utilities, from a high of 15 percent for HL&P to less than 1 percent for the remaining three utilities. With the exception of CP&L, these Texas electric utilities paid cogenerators (and small power generators) a purchase price less than the average price each paid for all purchased electricity.

  Each utility constructs payments for electric energy from cogenerators (and small power generators) based on discounted hourly avoided energy costs. Based on discussions with utility representatives, discounts of up to 10 percent are intended to ensure that utility customers are not subsidizing cogenerators. In addition, capacity credit payments are (or will be) based on the need for capacity, with HL&P being the only one of the four utilities currently paying capacity credits. As in the case of energy payments, payments for electric capacity will incorporate discounts for quality (e.g., reliability, size). These utilities do not expect capacity credit payments to be made to new cogenerators (and small power generators) until the 1990s. The representatives believe that with the current method of determining buyback rates, the customers of the utilities are not being penalized for the benefit of cogenerators located in their respective service territories. That is, the purchase of cogenerated electricity has not increased the average costs of each utility beyond those without purchased cogenerated electricity.

For the future, the utilities expect that, because of a greater dependence on coal-fired systems and stable prices for natural gas, avoided energy costs will either decline or remain near current levels. However, avoided capacity costs could increase as electricity demand continues to increase. Nevertheless, the actual buyback rates will be dictated in part by the rules and guidelines recently formulated (but not yet published) by the Texas Public Utility Commission governing long-term agreements between Texas electric utilities and cogenerators.

CONCLUSIONS

Based on the data available, several important conclusions can be made regarding the 10 electric utilities studied in detail. Overall, it appears that the only condition where industrial cogenerators selling electricity to a utility could detrimentally affect the utility's average cost of electricity is the use of long-term firm-price contracts. All other things being the same, the use of levelized firm prices could cause near-term increases in average utility costs, but reduce average costs in the long term. However, if the economic assumptions used in formulating the firm price do not occur, the average utility costs could increase (or decrease) to levels that would not occur otherwise. In discussing these conclusions, it is important to distinguish between four different costs: (1) the calculated (projected) avoided costs, (2) the contracted price, (3) the price actually paid, and (4) the actual avoided cost.

All utilities are required to calculate avoided costs. The specific methodologies involved in making these projections are at least approved, if not defined, by the pertinent state regulatory commissions, and may be either utility-specific or state-specific. These cost projections are used in several ways: the potential cogenerator (and small power generator) uses the calculated avoided cost to evaluate the economic viability of selling electricity to the local utility; the calculated avoided cost is used as a basis for contract negotiation (i.e., contracted price) between the cogenerator (and small power generator) and the local utility; and in some instances, this cost forms the basis of buyback rate schedules (i.e., contracted price) that are offered to all cogenerators (and small power generators) satisfying (or desiring) specified terms and conditions. In contrast, the actual avoided cost is used to evaluate the reasonableness and accuracy of the calculated (projected) avoided cost, and is used by many utilities to adjust the contracted buyback rate and establish the actual delivered price to be paid cogenerators (and small power generators).

All 10 electric utilities and their governing utility commissions are aware of the possibility that actual avoided cost may be different from calculated avoided cost, and in the event that actual costs are less than projected costs, action must be taken to prevent utilities (and their customers) from subsidizing cogenerators (and small power generators) through increased average utility costs (and retail rates) that would not have occurred otherwise. In contrast, the commissions in particular recognize that it is desirable to establish contract prices (buyback rates) that provide some reasonable level of certainty (e.g., firm price) to cogenerators (small power generators). The mechanisms adopted to protect utilities (and their customers) vary and have different levels of effectiveness. For instance, in Texas the electric utilities pay less than avoided energy costs to correct for possible detrimental effects on utility customers. In other states, the contracts between cogenerators (and small power generators) and utilities provide for "trueing-up" after the actual avoided costs have been determined.

Apparently, the greatest problem to date is related to the long-term firm contract price, which does not have a mechanism for adjusting the delivered price for purchased electricity based on differences between actual and projected avoided costs. Although the California Public Utility Commission recognizes this problem and is taking corrective action, it is apparent from discussions with utility and commission representatives that California utility customers may have been penalized to an unknown degree because of the economic assumptions used to formulate Standard Offer No. 4 compared with economic realities. However, many of these same representatives point out that with a different set of economic realities, cogenerators (and small power generators) would be penalized.

In summary, the analysis indicated that any adverse or detrimental effects of cogeneration (and small power generation) to utility customers should not exist over the long term. In principle, the mechanisms either have been or are being implemented to ensure that the prices paid for cogenerated electricity do not exceed a utility's actual avoided cost over a reasonable period of time. If one assumes that avoided costs are accurately determined and applied, as is the premise of this study, the utility and its customers should be indifferent in the long run to the amount of cogenerated electricity purchased. In the short run, however, the cost of purchasing cogenerated electricity could increase average electricity costs, forcing utility customers to pay higher rates.

The CHAIRMAN. Dr. Jan Hamrin.

STATEMENT OF DR. JAN HAMRIN, EXECUTIVE DIRECTOR, INDEPENDENT ENERGY PRODUCERS ASSOCIATION

Dr. HAMRIN. Mr. Chairman, Senator Evans, ladies and gentlemen. I appreciate the opportunity to be here today and to make a few additional comments with regard to the implementation of PURPA.

My name is Jan Hamrin. I am executive director of the Independent Energy Producers Association in California. I am President of newly formed independent energy producers forum in Washington.

I would like to outline for you some of the reasons why I believe that PURPA is a magnificently constructed piece of legislation which is achieving exactly what it was designed to achieve, which I know is legislative circles is not real common, and urge you to not change it.

I think that it embodies a flexibility and approach which is able to deal with any and all of the issues that have been brought here today. And I think the main difficulty has been in learning to implement.

Implementing PURPA is not easy. I would say that it is something like learning to do downhill skiing, but you don't criticize the downhill racer for the falls he or she made when they were learning to ski. I think we do in fact have a couple of downhill racers and others that now can follow the lead and learn the skills that are required to implement PURPA in their own States.

I think that the two particular characteristics which make PURPA very amenable to dealing with and achieving the results that were envisioned are, one, the avoided costs standard, and, two, the State-by-State implementation.

I would like to briefly summarize some of the issues that have been discussed and how I think they are dealt with under the present PURPA Statute, but as you will notice, I have quite a lengthy written testimony that was submitted that goes into detail on these, and I won't bother to do that level of detail unless you have particular questions.

One of the first issues that has been discussed many times this morning is economics and supply. Basically, PURPA says that a utility must purchase the power from a QF, unless there is a negative avoided cost situation, unless, in fact, the utility can generate that power themselves for less than the avoid cost price set, at which point they do not have to purchase the power.

Beyond that, I think confusion arises between long-term and short-term measures of avoided costs and what a utility needs in the long-term. If a regulatory commission has done the calculation, looked at the resource plans and needs of a utility, determined that, but for qualifying facilities, it would need a new generational facility at a certain point in time and has established the value of the power at that point in time, and put out an offer for the electricity and capacity that would otherwise have been provided by the utility power plant, then recalculates based on those qualifying facilities, applying that capacity and electricity—energy needs, the new needs for the utility, and at that point, very likely, the utility does not need another power plant or, a bit further into the future.

And then someone says, well, look, the price of avoided costs is very low now because they don't need any capacity or energy. Therefore, the people who are already contracted shouldn't be paid those prices; that is an overpayment.

That is a misunderstanding and a misuse of the avoided cost measure because, in fact, it is like telling a utility who needed power, and built a plant that, after they built the plant for exactly what they said they would build it for—and I know that is a far-fetched idea—that in fact, they should not be paid for it because now they don't need it because that plant is now in existence.

I think that a long-run contract is important, or the long-run planning and calculations of avoided costs are important because they do provide the yardstick, and a common yardstick that can be used for measuring the needs for capacity, for energy, for new power plants, whether it is by a utility or qualifying facility, for conservation and load management programs, and using that yardstick, even if the determination at the other end is in fact the utility needs very little if anything, is a valuable tool that did not exist before PURPA.

If a utility does not need capacity or energy, avoided costs or capacity will approach zero, and similarly, the energy value will be very low.

In theory, a utility can always use energy if it is cheap enough. If, in fact, someone can provide energy to the utility cheaper than they are paying otherwise, then it is a benefit. So that the negative avoided cost standard does allow the utility to stop purchasing, when in fact they have reached a point when they can't back down anything any further and would otherwise be generating themselves for less.

But it still allows the rate-payers to get the full benefits of competition, which is part of the importance of this whole measure.

In the reliability area, in 1977, I think, Pacific Gas and Electric Company came into the California Public Utilities Commission and said that Diablo was 6 months away from operation. Had everyone believed everything that was laid in front of them they would not at that point have contracted with any qualifying facilities because they would have assumed that they had everything that they needed.

In fact, Diablo Canyon Nuclear Generating Unit did not come on line until 1985 and 1986, and in 1984, Pacific Gas and Electric had a reserve margin of 6 point 5 percent. There was 5 percent qualifying facility generation on line at that point.

If the QFs had not been there, PG&E would have been in the situation of rolling blackouts throughout the State. That energy was needed and that capacity is still needed today.

With regard to safety, and I have heard this one as long as I have been in this business and we have always been concerned that that lineman is protected out there on the line, but in fact, in California and most other States in which I have been fortunate to work, the interconnection facilities are designed by the utilities, themselves. They are designed to utility engineering specifications. They are frequently even constructed by electrical engineers who, in fact, at other times are constructing interconnecting facilities for the utility, itself, and then they are inspected by the utility before the project comes on line.

So I have not found safety to be a real issue in any location, assuming everyone does their job correctly.

The only issue is that sometimes there are those who think that the specifications for those interconnection facilities are rather overengineered and goldplated, but that is an economic debate that goes on.

I think some of the issues that were raised by Mr. Peevey of Southern California Edison have some validity in looking toward the future at larger percentage of qualifying facilities coming online in a particular utility area.

We are working in California to develop contractual, operational options which would provide incentives for qualifying facilities to give utilities a number of other operational benefits that are not presently captured in avoided costs, or may not be presented in a strictly baseload mode of operation.

Those, again, can be done within the framework of PURPA as it is presently written.

Basically in California, we have a package of contracts, not just one contract, but a package of contracts that provides tremendous operational flexibility and pricing flexibility for the ratepayers and for the utility. Gas cogenerators in California are prohibited from taking a long-term fixed-price contract over 20 percent of their operating capacity and energy.

Instead, they are offered a contract which has a projection of the incremental heat rate for the utility, which is a measure of utility efficiency that is then multiplied by the actual fuel costs—fuel that the utility is burning.

Since the gas cogenerator pays the same cost for fuel as the electricity utility pays for the gas that they burn, then the gas cogenerator makes a profit by being more efficient than the utility.

It is not a requirement—there are no specific efficiency standards listed, but in fact, that cogenerator's profit is based on his ability to be more efficient and the more efficient he is, more efficient than the utility operation, the more profit he will make.

In the spot market prices, they look very, very good for ratepayers when the cost of fuel is going down. With natural gas prices at rock bottom, it looks wonderful to ratepayers. When and if those prices go back up, and I think most people in this room would agree that they will, although we can't necessarily know what date and time that will happen, then a fixed price looks better to the ratepayers because they have stabilized their rates. They know exactly what they will pay for the electricity, and remember, qualifying facilities are only paid for generating kilowatthours.

They are not paid for projects that do not operate. They are not paid for cost overruns. They are not paid for the other kinds of risks and costs that are usually incurred by standard utility plant construction.

So this combination of contracts which did require a lot of work and time to develop, and is a sophisticated application of PURPA in California, has resulted in diversifying the risks of California ratepayers across technologies, across geographic areas, across different contract types.

One might think from listening to the previous panel that this room would be absolutely jammed with consumer representatives demanding that you repeal PURPA because it is ripping off consumers in this country. In fact, I have yet to come across a consumer group who is concerned that PURPA and avoided costs are costing them too much and causing them a lot of problems.

I hear constantly from utilities, public utility commissions who are really charged with balancing the interest of the ratepayers with those of the utility shareholders, with those of other interested parties, are not giving away the store, and they are considering the needs of the ratepayers in developing these contracts and contract terms.

But as I mentioned, it is not easy. Not every State is in the same point of development. It does require talented staff and people who are willing to put time and effort into implementation of PURPA, and it requires a lot of hard work on all sides to achieve the results. But I do believe they are achievable within the act, itself. I think it was ingenuously crafted and I think it is working and will continue to work very well.

The issue in 1986 is not price of QF power, nor is it resource. I think the issue in 1986 is competition.

For the first time, there is real competition in the electric generation side of the electric utility industry. If I had a monopoly in the industry, I don't think I would be real thrilled with someone introducing competition to something I had all to myself up to that time. And I think that is the issue and it is a natural struggle by the electric utility industry in this country to redefine what their role would be if, in fact, they never had to build another central generating station again.

It is an understandable concern and one that we will all work through in trying to resolve, but I think that the bottom line is that PURPA is working beautifully. I think it is a more gracious to integrating competition into the electric utility industry than immediate deregulation.

I thank you very much for both passing it, and I hope that you will not change it.

[The prepared statement of Dr. Hamrin follows:]

ACCOMPANYING
TESTIMONY OF
JAN HAMRIN, PH.D.
EXECUTIVE DIRECTOR
INDEPENDENT ENERGY PRODUCERS ASSOCIATION (CALIFORNIA)
AND
CHIEF EXECUTIVE OFFICER
INDEPENDENT ENERGY PRODUCERS FORUM

BEFORE THE
UNITED STATES SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

REGARDING

IMPLEMENTATION OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

IN BEHALF OF
AMERICAN WIND ENERGY ASSOCIATION
INDEPENDENT ENERGY PRODUCERS ASSOCIATION
INDEPENDENT ENERGY PRODUCERS FORUM

WASHINGTON, D.C.
JUNE 3, 1986

TESTIMONY OF JAN HAMRIN, PH.D.
FOR THE INDEPENDENT ENERGY PRODUCERS ASSOCIATION, ET. AL.

Introduction

By the end of 1985, California's independent energy producers had brought one-third more power on line (2,875 MW) than both Diablo Canyon Nuclear Power Units 1 and 2 in seven years at roughly one-half the cost per kilowatt hour (see Attachment A). For the first time, there is a viable alternative to traditional utility power plants at a very competitive price. This enviable situation has come about as a result of the Public Utilities Regulatory Policy Act (PURPA) passed by Congress in 1978.

In 1977, a PG&E witness testified before the California Public Utilities Commission (CPUC) that "Diablo Canyon is only six months away from being fully operational". Eight years later, in 1985, Diablo I became operational; in 1986 Diablo II became operational. By 1984, PG&E was down to an actual reserve margin of 6.4%*. During this period, independent energy producers were providing 5% of PG&E's energy and capacity. Without them, PG&E would have had rolling blackouts.

PURPA is a beautifully designed piece of legislation which is achieving the results it was intended to achieve: bringing competition and improved efficiency into the electric generation side of the electric utility industry and encouraging the development of facilities not dependent upon imported oil and which result in minimal environmental impacts. Further, it accomplishes this through the use of market forces and competition rather than monopolies and regulation. This testimony provides specific examples of the growth of cogeneration and small power production since passage of the Act, how payments to qualifying facilities are calculated and the effects of such purchases on electric utility operations and reliability. It is my opinion that there is no need to modify PURPA. Rather, the success or failure in reaching the goals of the Act lie in its thoughtful implementation. There are two characteristics of PURPA which have been central to its success which I would like to discuss further with you: avoided cost pricing and state-by-state implementation.

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*Testimony by PG&E Executive Vice President Mason Willrich in 1986, PG&E Rate Case (TR. Vol. 2, page 239-240)

AVOIDED COST

Central to the successful implementation of PURPA is the concept of avoided cost. Avoided cost is a mechanism for approximating the market value of electricity (electricity previously produced by a monopoly/monopsony industry). The advantage of this concept is that it can be used as an effective mechanism for obtaining energy at a fair price for ratepayers using market incentives. The disadvantage is that to use the concept effectively to obtain the desired results is not simple or easy. But it does work incredibly well in a wide variety of circumstances given sufficient care and thought to implementation. When used with its flipside, negative avoided cost, there are no significant limitations to its use. The following are some examples of its use, perceived problems, and solutions to those problems.

How Do You Measure Avoided Cost? Short-term and Long-term

The avoided cost concept can be used to measure short-run avoided cost (marginal operating costs and shortage costs) as well as long run avoided cost (the capital and operating costs which would have been incurred by the utility in new generating facilities "but for Qualifying Facilities--QFs"). Part of the confusion and criticism of PURPA implementation lies in these two values--how they are computed and how they compare. They are both important and mutually compatible in measuring the present and future needs for power by a utility. The short-run avoided cost can vary significantly from month-to-month or year-to-year depending upon the types of resources (fuels) a utility has to utilize. Long-run avoided cost can be calculated in such a way that it levels out some of the short-term perturbations (peaks and valleys) and also incorporates the potential investment in new capacity if such is needed by the utility. If no new capacity is needed during the time period used for evaluation then long-run avoided cost will simply be a projection of short-run avoided costs.

Avoided cost (both long-run and short-run) is comprised of two components: a capacity payment and an energy payment. If the utility needs little capacity (though additional capacity always has some value--see supplemental material), then the capacity portion of the avoided cost payment will approach zero. California has already adopted a method of recognizing the need for capacity for one utility and is currently in the process of implementing this mechanism for the balance of the utilities in the state. This mechanism allows avoided capacity costs to accurately reflect the utilities' changing capacity needs, reserve margin and expectations of unserved energy requirements (see backup materials on long run avoided cost contracts). If the utility has little need for additional energy, then one would expect the short-run avoided cost for energy to be very low. However, energy is always "needed" if it is cheap enough, i.e., less than what the utility is currently paying (except under conditions of negative avoided cost when the utility does not have to purchase QF power). Thus, the avoided cost concept when properly implemented can, through the use of price signals (the essence of our economic system), encourage the production of additional generation.

Methodology For Long Run-Avoided Cost

Long-run avoided cost, if properly implemented, should reflect either the capital and operating cost of new utility generation sources at the time they are added (otherwise known as the "proxy plant" method) or the short-run marginal cost calculated assuming the existence of these proxy resources, whichever is higher. The conceptual method for calculating long-run avoided cost is based on the simple premise that avoided cost cannot be less than the cost of a new utility generating unit. If a utility were building a plant that cost more than the avoided cost, then one of two things is wrong: either the plant is not cost-effective and should be cancelled or deferred or the avoided cost has been calculated incorrectly. This issue has arisen in testimony in implementation of PURPA in a number of states including California, Montana, Connecticut, and North and South Carolina.

Importance of Long Run Avoided Cost Offer

QF projects are generally built with an expected life of 15 to 30 years. It is difficult if not impossible to finance a capital investment of this type without some assurance of a revenue stream at least over the early period of "debt service" for the new plant. A long-run avoided cost offer provides this stability. In addition, a long-run offer allows the utility and the regulatory commission to do long-range planning which can attract QF development to avoid or defer the need for a large central station, utility power plant.

Lack of a Long Run Avoided Cost Offer (Methodology) Can Lead to Catch 22

Without a long-run avoided cost methodology, the situation will shift from one in which no additional capacity is needed by a utility to one where the utility has begun a new plant which they claim "cannot now be avoided" thus eliminating the ability to interpose QF generation as an alternative.

Utilities often turn the timing of their future need for capacity and the short lead times of QFs to the disadvantage of QFs. If capacity is not needed now, but is needed, for example in six to ten years, utilities try to discourage QF generation now. As a result, few QFs sign contracts. Then the utility commits itself to its own new generation capacity (which has to be committed early because of its longer lead time than QF capacity) and argues that the QFs cannot avoid the new capacity because it is already committed. We are aware of an example where the Duke Power Company did not even include a pumped storage plant in its resource plan for determination of avoided cost in 1982 but stated that the plant was committed and unavoidable by QFs in 1984. This "Catch 22" can only be prevented through the use of long-term contracts.

Related to this issue is the claim by many utilities that forecasting prices increases "risks" to ratepayers for which ratepayers must be compensated. When the issue is evaluated in its full context, it becomes clear that extra risks are not imposed on ratepayers through a long-term forecast of avoided cost. The proper evaluation must consider the utility system as a whole rather than looking at QFs in isolation. If QFs are not built, the utility must add new generation. The type, timing, and amount of this new utility generation will be justified on the basis of the utility's long-term forecasts. Thus, the ratepayers do not avoid the "risk" of long-term forecasts if long-term contracts are not offered to QFs which reflect their value to the utility system.

Without such contracts, QFs will simply not be built, and the ratepayers will bear the risk of long-term forecasts for utility-owned projects rather than QF projects.

Further, forecasting prices in advance reduce risks by actually providing ratepayers with more certainty as to what their exposure is. QF payments stabilize electric rates under such conditions. Forecasted prices would be overstated relative to the original projections at times ratepayers are receiving benefits from lower fuel costs and understated when utility fuel costs are high. QF payments based on forecasts of avoided costs indeed prevent the ratepayers from reaping all the benefits when actual fuel costs are lower than forecast, but conversely, the existence of such contracts insures the ratepayers against paying higher fuel costs if forecasted costs are less than actual and higher costs for new generation if a new plant has cost overruns and/or comes in later than anticipated.

QFs With Long-Run Avoided Cost Contracts Change the Risk Pattern For Ratepayers

Qualifying facilities change the risk pattern for ratepayers from what it is under traditional utility built powerplants. The major reason is that QFs are only paid when the produce energy. Developers of qualifying facilities assume the following risks from ratepayers:

1) **Sunk Costs of Cancelled Plants.** Utilities routinely collect millions of dollars from ratepayers for cancelled plant costs. PG&E recently collected $47 million of these funds.

2) **Costs of Preoperative Plant.** In a jurisdiction which includes CWIP in rate base, ratepayers must pay for a plant before it generates energy. A QF is not paid until it produces electricity. Even without CWIP in rate base, ratepayers pay more indirectly through higher required equity returns if the utility has an extensive construction program and through increased embedded debt and preferred stock costs.

3) **Cost Overruns on New Plant Construction.** Absent imprudence, ratepayers generally pay for cost overruns on utility plants. A QF is paid based on the value of its energy regardless of production costs.

4) **Plant Failure to Perform Within Reliability or Efficiency Specifications.** The ratepayers must again, in the absence of imprudence, pay for higher costs per kilowatt-hour resulting from spreading fixed costs over fewer kilowatt-hours, O&M costs higher than projected, and the cost of replacement power if a utility plant does not perform as well as its proponents had planned. By contrast, the QF must absorb the higher costs and lower output resulting from such failures.

The most extreme example of such failures involve early termination of a utility plant after it has received frontloaded payments to recover its capital. Such frontloading may create a ratepayer risk even greater than levelizing QF payments. Therefore, the QF early termination risk must be viewed in this perspective. Early terminations of utility plants are not academic but have occurred in the past. To provide several examples, Pacific Gas & Electric Company's Humboldt Bay No. 3 nuclear plant only operated for 14 years before being closed for seismic safety reasons. Ratepayers paid over $40 million for the undepreciated capital. The Indian Point 1 and Dresden 1 nuclear plants also closed after less than 20 years of service.

5) **Uncertain Future Dismantling or Decommissioning Costs.** The cost of decommissioning the Diablo Canyon Nuclear Plant was estimated at $105/kw in 1983 dollars in 1980. It has more than doubled and is now estimated at $214/kw in 1985 dollars despite very limited inflation in the 1983-85 period. Decommissioning costs of conventional units are also rising. Deloitte, Haskins, & Sells has recently advised utilities to increase depreciation expense and negative net salvage rates for fossil fueled plants. QFs, which are only paid to produce power, must absorb these costs.

Avoided Cost Takes on the Role as a Common Yardstick for Utility Planning

Avoided cost and long run avoided cost offers provide a common yardstick against which to measure various conservation and generation options. As is explained in the background paper on long-run avoided cost methodology, conservation programs, refurbishments, firm power purchases, and new generation sources which are found to be "inframarginal" should, according to economic theory, be built (or funded). Other generation or purchase options are then assessed with regard to what would be used "but for QFs" and incorporated in setting a long-term avoided cost rate. If no need is found (within the planning horizon being used) for new generation, QF or otherwise, avoided costs will simply reflect short-run operating and shortage costs. Thus, the avoided cost implementation process and methodology have become useful planning tools for regulatory commissions in assessing the options utilities have before them for managing and meeting their electricity demand. Further, we have seen in California that the QF industry has improved the PUC's regulatory process by finding and pointing out inconsistencies in utility testimony relating to QF and other issues thereby providing the Commission with more needed information on utility resource plans and revenue requirements.

How Do You Keep From Getting Too Much QF Power in the Long-term?

Long-run avoided cost offers based upon displaced plant(s) can be limited to the size of that plant(s) in megawatts or a megawatt limit can be used based upon a utility's annual growth rate. When the megawatt limit is reached, new calculations are made and a new offer (price and megawatt limit) issued based on the new circumstances. If no additional capacity is required during the next forecast period, the "new" offer may only reflect short-run marginal operating costs until (through regular revisions) additional capacity shows up in the utility's resource plans. Thus, the use of market forces (avoided cost) works very well. When little new energy or capacity is needed, the avoided cost price will be very low. New qualifying facilities will not be cost effective under those prices and will not be built. When energy and/or capacity are in greater need, prices will be higher and the private sector will respond.

Long Run Avoided Cost Offers Make Self-generation for Utility Bypass Less Likely

PURPA does not in any way encourage utility bypass by large industrial customers in times of high electricity prices and in fact contributes toward lessening such behavior. Long-run avoided cost contracts make sale of excess generation to the utility and use of the utility as back up more attractive and can result in fewer industrial customers leaving the system entirely to serve their own loads.

STATE IMPLEMENTATION

PURPA Implementation is not Easy

State-by-state implementation of PURPA is both a strength and a problem. Implementation of PURPA to achieve the desired results is neither simple nor is it a "one shot process." The regulators, utilities, and interveners must be very thoughtful and sophisticated in their development of a QF program if it is to be effective. All parties must keep the concept of ratepayer indifference as the short-term criteria and ratepayer benefits as the long-term goal.

Effective PURPA implementation also requires regulatory review to ensure the methodologies adopted are achieving the desired goals and regulatory updating of input assumptions in order to respond to changing situations and needs. At the same time regulators must imbue the program with a backbone of regulatory stability, consistency and enforceable long-term contracts. This is no small feat. As can be seen from the examples which follow, all of these issues can be dealt with within the current Act through state implementation.

California Implementation

The California Public Utilities Commission has come as close as anyone to achieving the goals listed above. Though the California program has not been without its learning problems, none of these problems have been either fatal nor insolvable. The success of PURPA implementation in California is due in large part to a regulatory commission, interveners and utility representatives who were willing and able to put in the time, effort, talent, and resources necessary to achieve desired results. The following is a summary of some of the California program features which may be relevant to the questions being asked here today.

The California Long-Run Avoided Cost Offers

The Califoria Public Utlities Commission adopted an interim long-run avoided cost contract offer in September 1983 and is in the process of adopting a final Long-run avoided cost contract Offer No. 4 which will be revised periodically along the lines mentioned above.

The interim contract (Standard Offer No. 4) had two capacity options: 1) as-available capacity and 2) firm capacity. It also has three energy options: 1) a projected avoided energy cost (over the first 1/3 of the contract term--with a spot market energy cost over the last 2/3rd's); 2) a levelized energy cost for first one-third of contract with the same present value as (1) above or; 3) for gas cogeneration* a projection of the incremental heat rate for the utility using the spot market fuel price to calculate the floating avoided energy cost.

The implementation of a long-run offer in California by the CPUC has been slow but painstakingly developed and has turned out to be an elegant application of market forces at work. Ratepayer risks are diversified across technologies, geographic locations, project sizes and types of contracts. A "package" of contracts has been developed which, when viewed in total, provide exceptional benefits to California's ratepayers and great flexibility to independent energy developers. The fixed price contracts are good for ratepayers when fuel prices are high and rising; spot market prices are beneficial when fuel prices are low (see supplemental materials). Approximately one-third of the QF contracts are on fixed prices and two-thirds are spot market (floating price). Cogeneration contracts have a built in incentive to improve thermal efficiency (see pp 18-20). Economy energy is included in the calculations of avoided cost (page 18) so the ratepayer is economically indifferent to QF purchases or out of state purchases. (Though as California taxpayers, ratepayers may have a preference for projects which bring economic development and jobs into the state).

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*Gas cogenerators are prohibited from taking a fixed contract in California for more than 20% of their energy output and instead are offered a price which floats with the cost of gas.

One learning error made in the California long-run program was in not implementing it sooner. The Interim Offer No. 4 had no mechanism for updates and revisions. Thus, when it appeared sufficient contracts had been signed, the only option was to suspend the offer until a final methodology including a process for revision could be adopted. The final QF program in California as it is being finalized is not an accident. Rather, the PUC and interested parties have spent literally years in developing this program and balancing the interests of the ratepayers (long-term as well as short-term) with those of utility shareholders and the QF industry. Nor is the program finished. The CPUC is presently considering ways to include more operational flexibility into QF contracts (see supplemental materials) and is constantly reviewing the types of questions raised here in an effort to keep the program in balance. A discussion of some of the more specialized issues follows.

The Reliability and Control of Qualifying Facilities

Three criticisms of qualifying facilities raised during the drafting of PURPA and after its passage which should have been laid to rest by now continue to resurface though they contain little or no substance.

Safety: Utilities have consistently complained that third party generation could pose a safety threat to utility workers or the public at large. In California (and every other state where I've worked), the electrical engineering of QF facilities and interconnections are done to electric utility specifications by certified electrical engineers who are sometimes building identical interconnection facilities and substations for the utility itself. The utility, with the guidance of the regulatory commission, sets specifications; the industry builds to those specifications and the utility inspects the equipment and interconnections before the facility is brought on line. If there is a problem, it is one of overengineering and "goldplated" specifications.

Reliabililty: "How can you depend upon qualifying facilities to provide power? After all, only the utility has an obligation to serve." Answer: Independent energy producers only get paid when they produce electricity. Unlike utilities, they do not get paid if their system does not operate for one reason or another. As business people, the incentive is to generate electricity because if nothing is generated they do not earn any money. Time differentiated avoided cost pricing is used in California and most other states to push qualifying facilities into producing electricity at the times it is most needed.

For a specific example of QF reliability, a utility witness in the current PG&E ratecase in California testified in the last few weeks that: Firm capacity qualifying facilities on the PG&E system have been generating at a 90% average capacity factor and as-available QFs at a 60% average capacity factor. It is important to recognize that these operational records generally exceed the reliability exhibited by utility power plants.

Control: This issue is best stated: as "If we do not own it, we can not trust it or integrate it into our system no matter what the facts." Another way of describing this issue is operational flexibility. Up to this point (9% QF ownership of California's electric generation) no proof has been submitted by any of the California utilities that there are any real operational problems due to QF generation (see supplemental materials).

Nevertheless, it is acknowledged that as the percentage of QF generation increases a more sophisticated approach to integration of QF and utility-owned generation is desirable. With this in mind, a number of options are being reviewed and considered by the California Public Utilities Commission to bring this about within the PURPA framework. Again, the supplemental materials on operational options contain a more detailed description of one of these proposals.

Incorporation of Economy Energy Into Avoided Cost Calculations

Short-run avoided cost calculations include consideration of the amount and cost of purchased power if purchased power is a marginal resource for that utility ("economy energy")--[supplemental materials on California Issues, page 3 for a discussion of economy energy issues]. In California (and most other states), economy energy prices (purchased power) are included in all avoided cost calculations (though they are handled differently for long run than for short-run calculations) in such a way that the ratepayer is indifferent as to whether the power is purchased from QFs or from another utility. The supplemental information submitted with this testimony indicates that 1) "economy energy" may not always be economical or in the best interests of ratepayers; 2) power purchased from QFs contributes to economic development and jobs within the state whereas power purchased from outside a state does not; 3) at present California utilities are not purchasing large amounts of economy energy "on the margin" (the only time it would be displaced by QFs) at a low price making it questionable whether any "economy energy" issue exists at all.

The Issue of Technology Mix and Gas Fired Cogeneration

There has been concern expressed that PURPA may not provide a balanced mix of technologies. If one looks at Attachment A, "Alternative Energy Projects in California", it shows:

Cogeneration is approximately 35% (by megawatt); Biomass, 28%; Wind, 28%; nonutility hydro, 7%; nonutility geothermal, 5%; and nonutility solar electric, 2%. If you add to these figures utility-owned hydro, geothermal, and solar, you will find California has a very diversified and balanced generation resource mix. Gas-fired cogeneration displaces utility gas-fired generation; so, unless there is more gas-fired cogeneration than utility gas-fired generation, (which there is not in California), the number is not additive.

Because gas-fired cogenerators pay the same price for fuel as utility gas-fired generators and since cogenerators are not paid on a fixed price contract but a formula (fixed incremental heat rate X floating fuel price), cogenerators make a profit by being more efficient than utility power plants. The more efficient they are, the more profit they make and vice versa.

This type of innovative approach to avoided cost contracts allows individual states to affect the generation mix which will be developed. A fixed price contract can discourage the development of gas-fired cogeneration while encouraging renewable energy projects. A combination of contract options as have been developed in California can diversify both the technology types and the ratepayer risks rather than having "all the eggs in one generation or contract type basket."

Approximately 65% of the Standard Offer No. 4 contracts (by effective capacity) are with gas cogeneration projects which have a floating price rather than a fixed price. The floating price paid gas cogenerators under Interim Standard Offer No. 4 is less than the current economy energy price (see supplemental materials). Thus, gas cogeneration can be very beneficial to ratepayers under certain circumstances. If state regulatory commissions are thoughtful and creative, they can design a QF program which incorporates gas cogeneration into that state's resource mix consistent with the other resources and needs of the state.

Implementation of PURPA is Improving the Quality of Regulation

As mentioned above, there are a number of aspects of PURPA implementation, particularly the use of avoided cost as a common yardstick for long-range planning and evaluation which have resulted in more detailed critical analysis than has occurred previously. In addition, because the assumptions used in the calculation of avoided cost are so intertwined in the whole regulatory process, interveners are now becoming involved in all electric utility regulatory proceedings, checking facts and figures, investigating computer models and questionning inconsistent utility filings in various cases. The regulators have in effect ancillary staff help. More experts are involved in all aspects of the the regulatory environment and as a result of this more thorough examination of the facts leads to better quality regulatory decisions.

State's Right to Go Beyond PURPA

A final note concerning state-by-state implementation of PURPA concerns the ability and desire in some areas to go beyond PURPA in providing incentives for qualifying facilities or for the development of certain types of technologies because of particular economic or environmental circumstances. As long as a state has gone through a thorough public review process weighing the benefits and costs of their actions, PURPA should not serve as the limiting criteria but rather as the minimum criteria beyond which regulators and/or legislators strive.

Today, there is much talk about deregulation of the electric generation side of the electric utility industry. Vigorous implementation of PURPA on a state level can be considered a more "graceful" introduction of competition than actual deregulation. In this regard, outright utility ownership of qualifying facilities--nonregulated monopoly/monopsony projects--is a jump back in the opposite direction.

Lessons Learned

In 1978, critics said 1) there's not enough of this stuff to matter; 2) it will not work any way; and 3) the private sector really is not interested in becoming involved in electricity generation.

In 1986, we find 1) there is a potential for even more of this "stuff" than is needed to meet present energy demands; 2) they work very well; 3) the private sector is quite pleased to move into the electricity generation business if the benefits offset the risks and 4) the private sector can usually do all this at costs significantly below new utility generation.

The criticisms of PURPA implementation (economics, reliability, safety, and control) where they are legitimate have resulted from the difficulty of implementing something totally new. The problems which have developed can be solved within the Act itself and have **not** resulted in permanent or even significant damage to ratepayers or the electric generation system.

Criticism of the program has come almost exclusively from the electric utility industry itself for obvious reasons. I have yet to hear a serious complaint from a ratepayer or consumer group except where they have felt PURPA was not being implemented fully or with sufficient rapidity.

The main lesson learned in California and other states over the past eight years is that PURPA is one of the most flexible, versatile, and creative pieces of legislation ever passed in the energy field (and possibly beyond). With leadership and sophistication, it can actually produce the results contemplated by its sponsors. The real issue in 1986 is the issue of competition. For the first time since Edison and Insull, there is actual competition in providing electric generation. PURPA is working well. We commend you for passing it and urge you not to change it.

ATTACHMENT A

3/86
(4th Quarter '85)

ALTERNATIVE ENERGY PROJECTS*

	TOTALS	ON-LINE	NONGENERATING** UNDER CONTRACT	DISCUSSION
PG&E				
Cogen/Biomass	6,969	666	4,183	2,120
Solar	36	7	9	20
Geothermal	175	81	94	0
Wind	2,400	458	1,917	25
Hydro	963	145	696	122
Other	26	2	24	0
55% TOTAL	10,569	1,359	6,923	2,287
SCE				
Cogen/Biomass	4,720	685	2,925	1,110
Solar	272	45	227	0
Geothermal	990	63	862	65
Wind	2,026	554	1,345	127
Hydro	200	76	89	35
Other	0	0	0	0
42% TOTAL	8,208	1,423	5,448	1,337
SDG&E				
Cogen/Biomass	588	79	499	10
Solar	7	7	0	0
Geothermal	0	0	0	0
Wind	2	2	0	0
Hydro	9	5	3	1
Other	0	0	0	0
3% TOTAL	606	93	502	11
TOTALS	19,383	2,875	12,873	3,635

*These figures were compiled from the Cogeneration Small Power Projects Quarterly Reports (Fourth Quarter, 1985) issued by the California utilities.

**Includes signed letters of agreement

California Peak Demand: Approximately 38,000 mW

3/86
(4th Quarter '85)

ALTERNATIVE ENERGY PROJECTS*

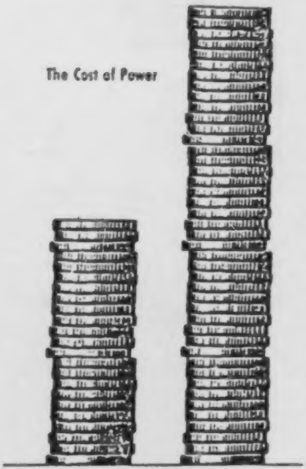
<table>
<tr><th>YEAR</th><th>TOTAL</th><th>ON LINE</th><th>NONGENERATIONG UNDER CONTRACT</th><th>UNDER DISCUSSION</th></tr>
<tr><td>1979</td><td>166 MW</td><td>5 MW</td><td colspan="2">161 MW</td></tr>
<tr><td>1980</td><td>372 MW</td><td>12 MW</td><td colspan="2">350 MW</td></tr>
<tr><td>1981</td><td>2,000 MW</td><td>200 MW</td><td colspan="2">1,800 MW</td></tr>
<tr><td>1982</td><td>3,841 MW</td><td>441 MW</td><td>1,800 MW</td><td>1,600 MW</td></tr>
<tr><td>1983</td><td>5,656 MW</td><td>956 MW</td><td>1,800 MW</td><td>2,900 MW</td></tr>
<tr><td>1984</td><td>17,926 MW</td><td>1,606 MW</td><td>9,165 MW</td><td>7,155 MW</td></tr>
<tr><td>1985</td><td>19,383 MW</td><td>2,875 MW</td><td>12,873 MW</td><td>3,635 MW</td></tr>
</table>

PERCENT &	PROJECT	ON LINE	NONGENERATING UNDER CONTRACT	DISCUSSION
63	Cogen/Biomass Total: 12,277 MW	1,430 MW	7,607 MW	3,240 MW
23	Wind Total: 4,428 MW	1,014 MW	3,262 MW	152 MW
6	Hydro Total: 1,172 MW	226 MW	788 MW	158 MW
6	Geothermal Total 1,165 MW	144 MW	956 MW	65 MW
2	Solar Total: 315 MW	59 MW	236 MW	20 MW
.1	Other Total: 26 MW	2 MW	24 MW	0 MW
	TOTAL 19,383 MW	2,875 MW	12,873 MW	3,635 MW

*These figures were compiled from the Cogeneration/Small Projects Quarterly Reports (4th Quarter, 1985) issued by the California utilities.

ATTACHMENT A

THE POWER OF CALIFORNIA



Alternative energy provides more electricity than Diablo Canyon at about half the cost.

Based on data filed by California's investor-owned utilities with the California Public Utilities Commission, and on PG&E applications now pending before the CPUC. Available upon request

Alternative energy. The utilities are counting on it to provide the new generating capacity California needs. In 1986 independent power producers will provide 30 percent more electricity than Diablo Canyon, at about half the cost.

We harness the hydro, geothermal, wind, biomass, waste-to-energy, cogeneration and solar resources of the state. And unlike the utilities, the ratepayers don't share our risks. As electric entrepreneurs, we're only paid for the electricity we generate.

By displacing fossil fuels, we help keep oil and gas prices down. We create thousands of jobs and millions of dollars of local tax revenue. We keep energy dollars from leaving the state. And we build quickly and efficiently. We are there when we're needed. Already eight percent of the state's generating capacity, we're growing with California.

The New Generation of Electric Power.™ Find out more about us.

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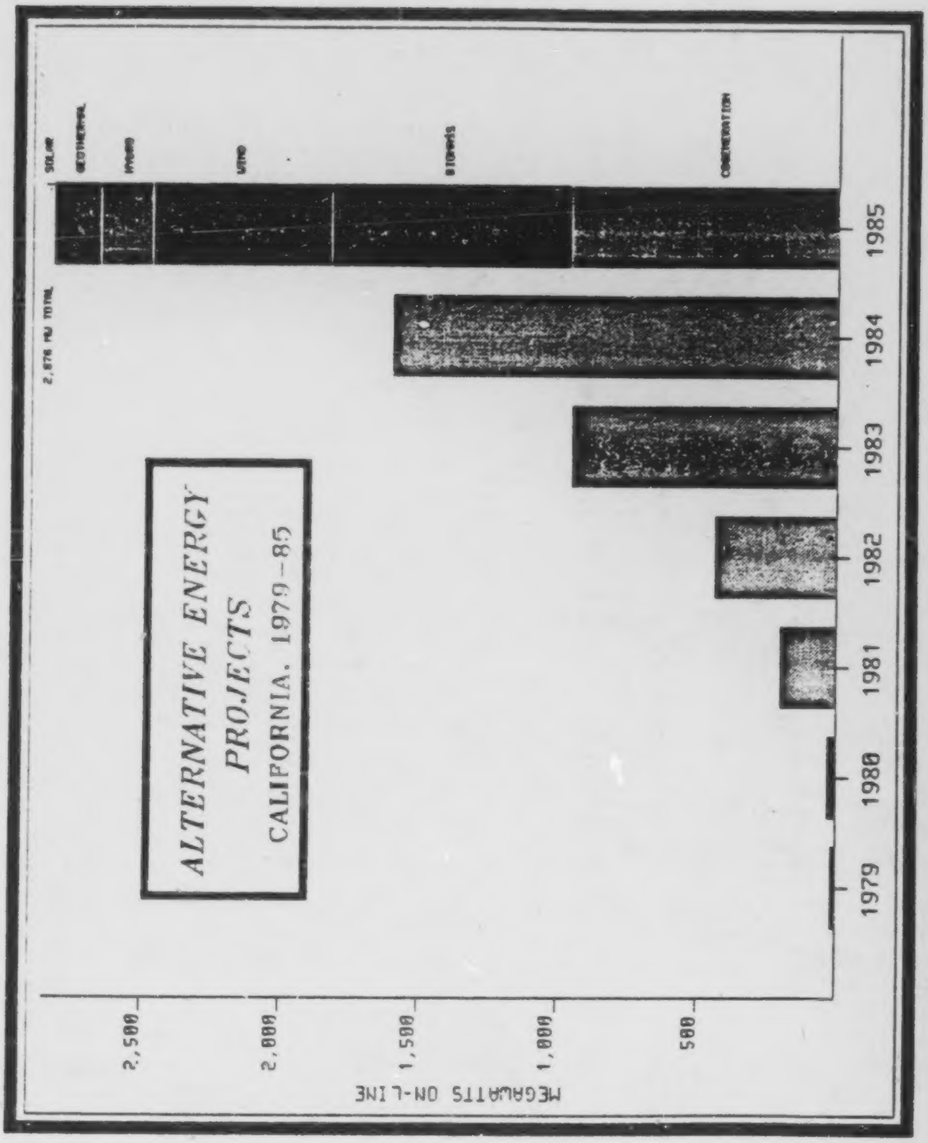
Andrews Energy Systems, Inc. • Applied Power Technology • Big Valley Lumber Co. • Catalyst Energy Development Corporation • Collins Pine Company • Crossflow Hydroelectric, Inc. • Dow Chemical Company • Gas Recovery Systems • GeoProducts Corporation • GWF Power Systems Company • Henwood Associates, Inc. • Howden Windparks Inc. • Independent Hydro Developers • Independent Power Corporation • International Power Technology • Louisiana-Pacific Corporation • Luz Engineering Corporation • Mega Renewables • Northwest Power Company • Pacific Lighting Energy Systems • Simpson Paper Company • TKO Power • Ultrasystems Incorporated

(As appeared in the Wall Street Journal--Western Edition on May 7, 1986)

ATTACHMENT A



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May 30, 1986

Hon. James A. McClure, Chairman
Senate Committee on Energy & Natural Resources
Senate Office Building, Room SD 358
Washington, D.C. 20510

Attn: David Doane, Deputy General Counsel

Dear Mr. McClure:

Enclosed are copies of the testimony of Jan Hamrin on behalf of the Independent Energy Producers Association (IEP) and the Independent Energy Producers Forum (IEPF) as well as some background materials for you to copy and distribute as you desire.

Trying to capture the key elements of eight years of work took more pages than I intended but there is a lot of ground to cover and concerns to be addressed.

The oral testimony on Tuesday will only highlight this material. Areas which you think warrant more in-depth discussion can be brought out through questidns.

In addition, if any of the committee or staff are interested in pursuing the topic further after the hearings, I will welcome the opportunity to meet with individuals or a group as desired within whatever schedule can be arranged.

I want to thank you and the Committee for providing us this opportunity to review the results and potential results of PURPA and hope when this exercise is completed the Committee and staff feel as pleased as I believe you should feel with the fruits of your labors.

I am looking forward to meeting you in person on June 3rd.

Sincerely,

Jan Hamrin

Jan Hamrin, Ph.D.
Executive Director

JH/og

Enclosures

916/448-9499

1001 G Street, Suite 103, Sacramento, CA 95814

INDEPENDENT
ENERGY
PRODUCERS

May 30, 1986

TO: David Doane

FROM: J. Hamrin

RE: Background Materials on Relevant PURPA Issues as They Have Been Argued in California

Many of the issues being mentioned for discussion at the Senate Hearings on June 3, and 5, 1986 have been raised in hearings in the California Public Utilities Commisssion and Legislature. The following are IEP's responses to those issues which may provide useful background information for your hearings.

JH/og

Enclosure: A--Background

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A--BACKGROUND

PURPA BACKGROUND ISSUES

ISSUE: **There is too much power in the state.**

There is no proof that there is too much power in the state right now and none that there will be too much power in the 1990's. The area of debate is whether there may be "too much" power for the next one to four years and that is not clear either.

1) The CEC's ER 5 was based on assumptions and data that resulted in a forecast which falls 10,000 GWh and 2,000 mw short of actual recorded energy demand for PG&E in 1985 and 1,000-1,500 mw short for Southern California Edison Company (SCE). (See Attachment A)

2) Utility demand forecasts in recent years have been much closer to actual demand than they had been in the past as indicated by the testimony of Mr. Schoonen in Tables VI-10 and VI-11 of SCE's filed testimony in A. 82-04-046. Pacific Gas & Electric (PG&E) has also filed testimony claiming the CEC Demand Forecast should not be relied upon for setting revenue requirements in their current rate case and ECAC (A. 85-12-50 and A. 86-04-12).

3) Conveniently, the utilities only support the CEC demand forecast when it comes to limiting QF projects and setting avoided cost rates. None of them have supported the CEC Demand forecast for setting their own rates.

4) But probably the most telling contradiction is by the CEC themselves. In their testimony submitted in the PG&E Rate Case, A. 85-12-050 filed last week (May 5, 1986), the CEC witness enclosed a chart (see Attachment B) showing that PG&E will need additional capacity, as

early as 1990 and '91 and states: "the chart above indicates capacity reductions have value throughout the period . . ."

5) According to accepted CPUC and CEC theory, energy is always needed if it is cheap enough (i.e., less than the utility is currently paying).

6) For some historic perspective on the issue of need, according to the testimony of Mason Willrich (March 25, TR. 2, p. 239 and 240) in the PG&E Rate Case, before both Diablos became operational (1983, 1984, 1985), PG&E was down to 6.4% actual reserve margin in 1984. Independent energy producers were providing 5% of PG&E's energy. Without them, PG&E would have had rolling blackouts. Now in 1986, it is assumed the state does not need more Qualifying Facilities based on a supply plan which assumes 60% capacity factors for all the state's nuclear facilities. Rancho Seco has been averaging 37% over the last five years and worse than that in the last year.

7) Finally, if oversupply of energy is the problem, why exempt utility plants and talk of exempting biomass, waste-to-energy, geothermal, solar thermal, etc.? In fact, a half percent error in the CEC Demand Forecast (low) could result in the state being 2,000-3,000 megawatts short on capacity in the 1990's. QFs narrow the margin for error. QFs are the only ones who can provide capacity of this amount in a short time if such a "capacity hole" should develop. Now is not the time for the legislature to signal "we have no need for future capacity from your industry."

ISSUE: "Economy energy" is being turned back at very low prices to purchase QF power at high prices.

In the past, up to 1983, "economy energy" was primarily "dump hydro" from the Northwest and was very cheap indeed--frequently under 1 cent/kWh. However, times, policies, and costs have changed.

1) The amount of excess cheap hydro power for sale to California is rapidly shrinking. The facts listed on the attached "fact sheet" (Attachment C) indicate present attempts by BPA to use this less expensive power in the Northwest itself. Interestingly, these facts are from CEC testimony at BPA hearings.

2) Because of the WPPSS nuclear plants, the debts incurred from these plants are now included in "economy energy" prices from the northwest. In fact, Californians are the only people in the U.S. paying CWIP in their "economy energy" prices. BPA nonfirm energy prices include both WPPSS #2 and the "sunk costs" so far for WPSS #1 and #3 (temporarily halted) and includes a subsidy to IOU (investor-owned utilities) residential ratepayers in the Northwest, so those IOUs will not be municipalized. This subsidy was supposed to be paid by the Northwest aluminum industry but California is paying a large fraction instead!

   In addition, this subsidy is paid to farmers in Oregon but not to farmers served by the same utility in California (Siskiyou and Del Norte Counties). **Thus these new "economy energy" purchases the CEC is promoting are paying to undermine our own farmers' competitive position as well as including the real risk of putting California ratepayers in the position of paying to finish the WPPSS No. 1 and 3 plants if the Northwest uses most of the cheap hydro power for themselves.**

   Thus "economy energy" from the Northwest can be expected to be more expensive now and in the future than it has been in the past. Also, though there is still some excess "less expensive" power available this year and for a couple more years, it could easily disappear just about the time most of the OF projects being discussed by the CEC would come on line.

3) Here are some examples of recent economy energy purchase prices. PG&E's average price for economy energy in 1985 was 2.6 cents. It's estimated average price for economy energy in 1986 is 2.16 cents. The lowest price they have paid for northwest economy energy in recent years (according to PG&E's latest 12-b system lambda filings) is 1.4 cents.

Economy energy was only on the margin for PG&E in the 12 months ending February 28, 1986 114 hours (out of 8,760 hours/year).

SCE has just signed a contract with BPA for "firm economy energy" at 3.7 cents/kWh plus about 2 mills for transmission losses (about 4 cents total).

SDG&E signed a contract for "economy energy" with Tucson Electric for 2 cents/kWh whereupon they claimed they should not have to purchase from qualifying facilities at 6.5 cents/kWh. However, in the 1985 SDG&E Rate Case, A. 84-12-15, it was found they had a demand charge equal to 8 cents/kWh; thus, this "economy energy" was actually 10 cents/kWh. The avoided cost paid to OFs was a much better deal for the ratepayers!

4) Economy energy estimates for SCE and SDG&E include the assumption that purchases will be made from southwestern utilities (overbuilding) building future coal plants to supply California's electrical needs. New coal plants are not economical at today's gas and oil prices. As demand increases in the Southwest, the existing overbuilding will be reduced decreasing the energy surplus with new plants more heavily weighted to peaking and pumped storage.

5) Finally, estimates of the amount and price of economy energy are included in the avoided cost calculations and price paid QFs thus ratepayers are indifferent as to whether power is purchased from QFs or from out of state. In addition, gas cogenerators get paid less for their energy than the present average economy energy rate (See Attachment E).

The main point of this discussion is: 1) economy energy may not always be economic or in the best interests to the ratepayers; 2) power purchased from QFs contribute to economic development and jobs within California; 3) at present utilities do not purchase that much economy energy "on the margin" (the only time it would be displaced by QFs) at a low price.

When SCE says they reject economy energy 20% of the time, this means during 20% of the hours in the year they may reject some amount of economy energy. This does not mean they reject 20% of the economy energy available to them.

Also, the utilities have indicated they have a major problem with minimum load. This was illustrated with a chart (Attachment D) showing a "typical day on the Edison system" which purportedly shows minimum load problems and resultant rejection of economy energy. We have seen this chart before (at the PUC in A. 82-04-046) where it was thoroughly discredited as showing anything useful:

a) January 2, 1984, was that once in 13 years when New Year's Day falls on a Sunday and thus Monday, January 2nd is a Holiday. Because it is in the winter and the holiday after New Year's Day, this is probably the lowest demand day one could find.

b) 1984 was not a typical year, in fact, it was the wettest hydro year on record.

c) January 2, 1984 was one of the few days anyone can remember when water was being spilled over Hoover Dam.

d) Songs II and III were not yet on line but under testing: thus, there was an exceptionally high "spinning reserve" requirement on Edison's system.

The point to all of this is: if the utilites really have a significant minimal load problem, why not use actual data rather than an example which is an obvious anomoly and which shows nothing. In requests by IEP and the CPUC for such "proof", the utilities have yet to provide any. Meanwhile, the CPUC is presently considering how to implement operational options into QF contracting.

ISSUE: Gas cogeneration is the main problem.

1) Ironically, gas cogenerators are prohibited from taking a fixed price contract (of more than 20%). They get paid the "spot market" avoided energy price which floats with fuel prices. The attached chart (Attachment E) shows the average price for economy energy as estimated by PG&E in their latest ECAC filings and the energy price which would be paid gas cogenerators according to PG&E's latest proposal in their GAC case.

   The only time gas cogenerators can displace economy energy is when it is on the margin (off-peak hours) thus gas cogeneration is better for ratepayers than is economy energy under the PG&E price scenarios.

2) Some people have stated they fear there will be gas shortages in the future making gas cogeneration impractical. It would seem that if this is the concern the CEC should be holding hearings on gas supply to discover if supply will in fact be a problem. No such hearings have been held--possibly because they would not yield the proper results. In fact, PG&E indicates that it does not do gas supply planning more than ten years in advance (Testimony of Mason Willrich in A. 85-12-50) and SoCalGas believes its supplies will be more than adequate to meet need.

3) There has also been an expressed concern that PURPA may not provide a balanced mix of technologies. If one looks at Attachment F, "Alternative Energy Projects", it shows:. Cogeneration is approximately 30%. Biomass. 28%: Wind, 28%: nonutility hydro. 7%: nonutility geothermal. 5%: and nonutility solar electric. 2%. If you add to these figures utility-owned hydro, geothermal, and solar, you will find California has a very diversified and balanced generation resource mix. Gas-fired cogeneration displaces utility gas-fired generation; so, unless there is more gas-fired cogeneration than utility gas-fired generation, (which there is not) the number would not be additive.

4) Because gas-fired cogeneration pays the same price for fuel as the utility gas-fired generation and since cogenerators are not paid on a fixed price contract but a formula (incremental heat rate x fuel price), cogenerators make a profit by being more efficient than utility power plants. The more efficient they are, the more profit they make and vice versa.

ISSUE: Does PURPA Include a Consideration of the Need for QF Projects

The CPUC includes consideration of need in setting avoided cost prices. The implementation of PURPA in California by the CPUC has been carefully and painstakingly developed and has turned out to be an elegant application of the free enterprise system at work.

Ratepayer risks are diversified across technologies, geographic locations, project sizes and types of contracts. Fixed price contracts are good for ratepayers when fuel prices are high and rising, spot market prices are beneficial when fuel prices are low (Attachment G). Approximately one-third of the QF contracts are on fixed prices and 2/3 are spot market (floating price). Cogeneration contracts have a built in incentive to improve thermal efficiency. Economy energy is included in the calculations of avoided cost so the ratepayer is economically indifferent to QF purchases or out of state purchases. (Though as California taxpayers, ratepayers may have a preference for projects which bring economic development and jobs into the state). The QF program is not an accident nor is the PUC more brilliant than the CEC. Rather, the PUC and interested parties have spent literally years in developing this program and balancing the interests of the ratepayers (long-term as well as short-term) with those of the utility shareholders and the QF industry. Nor is the program finished. The PUC is presently considering ways to include more operational flexibility into QF contracts and constantly reviewing the types of questions raised here in an effort to keep the program in balance.

Which Qualifying Facility projects actually develop is determined by the marketplace and the industry itself.

CONCLUSION

The issue is not the amount or cost of QF power in California nor is it the resource mix. The issue is competition. For the first time, there is a viable alternative to traditional utility built power plants at a very competitive price. This makes the utilities' large new plants look bad and it makes noneconomic "economy energy" look bad by comparison. **The QF program in California has worked well--that is the issue.**

B--BACKGROUND

BACKGROUND DISCUSSION OF LONG-RUN AVOIDED COST CALCULATIONS

Long Run Avoided Cost

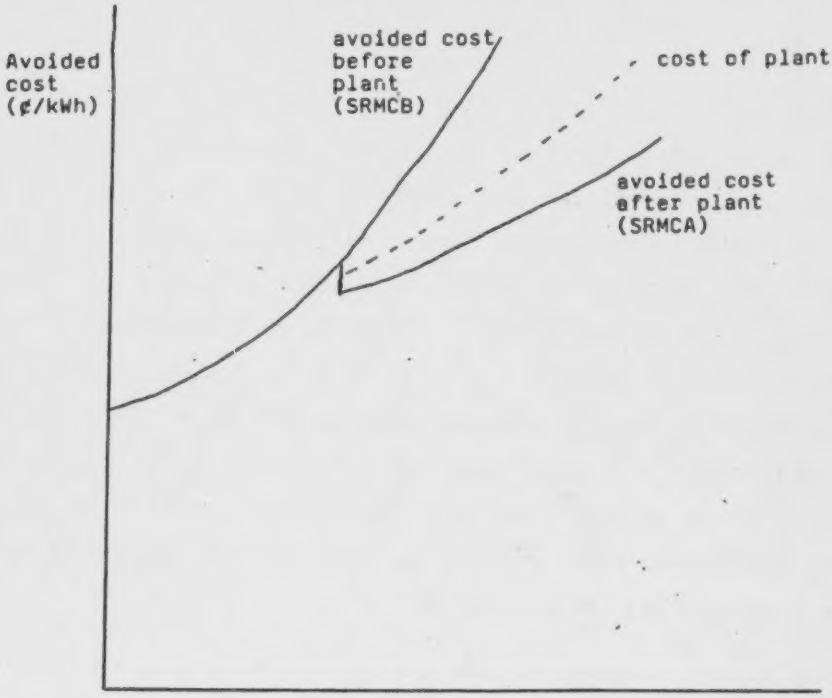
Economic theory suggests that long-run avoided costs should be equivalent using short-run marginal costs plus a peaker when capacity would be added (the peaker method), the difference in revenue requirements between two optimal resource plans, one with and the other without QFs, the total capital and operating cost of a new utility unit when it would be added (proxy plant method), and the total capital cost of a new unit, less that unit's fuel savings, plus short-run marginal cost (system planning method). (1, 2, 3, 4)

The debate over the proper long-run avoided cost methodology to use, arises from empirical rather than theoretical considerations. The critical assumption underlying the theoretical equivalence of all methodologies is that utility systems are in equilibrium and that new generation can be added in very small units exactly matching load growth. (1, 4) In such a case, the SRMC before a unit is added, on which the cost-effectiveness of the unit is based (SRMCB) is the same as the SRMC after the unit is added (SRMCA). With very small units, then, one would only add a plant if it is cheaper than SRMCB (or SRMCA). And in optimal equilibrium, one would continue to add plants until the cost of the plant equalled SRMCB or SRMCA.

Unfortunately, contrary to this theoretical construct, new generation is not generally added in small units but instead comes in discrete, relatively large units (a phenomenon which economists refer to as "lumpiness"). As a result of this lumpiness of new generation (which is generally added in units of several hundred megawatts), a gap often develops between SRMCB and SRMCA. (Figure 1) A utility will add a plant in order to reduce its total costs if the plant costs less than SRMCB). However, the plant, particularly if it is a low-fuel-cost baseload unit, may

Figure 1

Example of Situation When Short-Run Marginal Cost After a Plant Is Added Does Not Represent Long-Run Avoided Cost



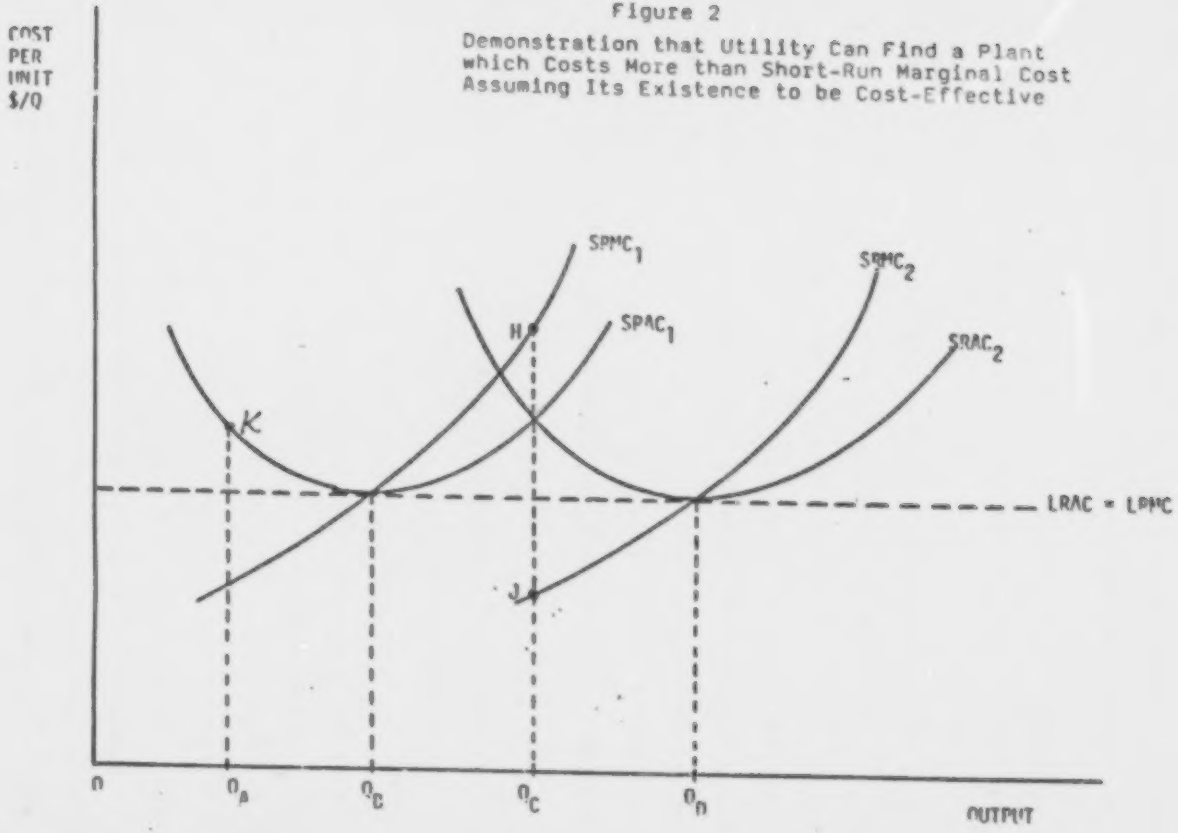
substantially reduce marginal costs to a very low SRMCA, even though the total capital plus running cost of the plant itself may be greater than SRMCA.

This concept is shown graphically as the difference between points H (on curve SRMCB) and J (on curve SRMCA) on Figure 2, from reference 1. A utility would find it cost-effective to build a new plant which costs more than point J but less than point H, as shown in Figure 2. In such a case, SRMCA does not represent the appropriate long-run avoided cost because it is cheaper than the cost of the plant that the utility would build. SRMCB also does not represent the long-run avoided cost because the plant is cheaper than SRMCB. In such a case, the cost of the plant itself is a better measure. (2, 3, 5, 6) A slightly more mathematical derivation of this concept is included in Appendix A.

The divergence between SRMCB and SRMCA is not just a theoretical construct but is evident in practice. Utilities often propose to build plants which cost more than SRMCA and justify them based on the savings of expensive fuel (e.g., from the higher SRMCB figures). A clear empirical example was presented by Carolina Power and Light Company. It justified several coal-fired plants projected for service in the mid 1990's on the basis that 25 to 60 percent of the energy that these units would produce would displace expensive energy from oil-fired combustion turbines and purchases from other utilities. Thus, SRMCB was high and rising. On the other hand, once the coal units were assumed to exist, SRMCB was quite low: only 4 to 8 percent of the marginal energy

Figure 2

Demonstration that Utility Can Find a Plant which Costs More than Short-Run Marginal Cost Assuming Its Existence to be Cost-Effective



Source: Reference 1, p. 1-13.

would come from these expensive sources. (2)

This theory leads to two different cost-effectiveness tests for new utility powerplants. (7, 8) The first test is a test for cheapness. Can the plant be built for less than SRMCA--the running cost of the system assuming the utility's entire resource plan is built. If so, the plant should be built regardless of the availabiity of alternative generation, and the alternative generation does not avoid the cheap plant but instead avoids the more expensive SRMCA. (7, 8) 1/ In front of the California PUC, this test has been denominated the "inframarginality" test. (8, 9)

A plant is cost-effective if it costs less than SRMCB plus a peaking unit. In such a case, the plant cost is likely to be a reasonable measure of avoided cost. SRMCB can be estimated by including all existing, committed, and inframarginal utility resources but replacing all uncommitted resources which are not inframarginal (such as plants under consideration for the 1990's) and all future estimates of alternative resources with peakers. If a plant costs more than SRMCB, it should not be built at all, and the existing system should instead be run for several more

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1. This "inframarginality" test shows the flaw in the oft-repeated argument in the late 1970's and early 1980's that conservation is bad because conservation will cause utilities not to build baseload generation to displace oil. (10) If baseload generation had indeed been so cheap that it should be built regardless of the utility's reliability, then conservation should not affect the need for it. (11) In fact, at least in the United States, baseload plants were largely not that cheap. (12, 13)

years until the plant becomes more cost-effective. In such a case, SRMCB is the right price to pay QFs.

The California PUC's Public Staff Division has provided an example of how this sequential inframarginality and cost-effectiveness test can be conducted under various resource assumptions. (14)

INDEPENDENT
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May 30, 1986

TO: David Doane

FROM: Jan Hamrin

RE: Background Paper on Operational Options for QF Projects Under PURPA

The following are some ideas for providing utilities with operational flexibility within the context of both new and existing QF contracts. These suggestions were contained in IEP's testimony filed January 6, 1986 and brief filed March 31, 1986 before the California Public Utilities Commission in Application 82-04-044 et. al. presently under consideration by the CPUC.

First, it should be noted that the California utilities have supplied no evidence that any real operational problems exist for which QF dispatchability is required. Attached is a copy of PG&E's estimated hourly marginal energy costs (Winter & Summer) for 1987. You will notice they are almost flat except for the "super off-peak" period of midnight to 6 a.m. (where we recommend a fourth pricing period). This "super off-peak" period can be handled through a curtailment option similar to the one presently in PG&E's Interim Standard Offer No. 4. Further, PG&E's own filings in the General Rate Case suggest that "minimum load" (hydrospill and negative avoided cost) occurs only 2 percent of the time; we note that contractual arrangements exist to deal with this problem.

We believe SCE and SDG&E have similar shaped marginal energy cost curves. Unfortunately, their reports in response to Ordering Paragraph 12 (b) are not filed in a detailed hourly basis like PG&E's. In fact, I recommend the PUC request such data in order to better assess what if any dispatchability problems these utilities face.

With this said, I would "put the ball in the utilities' court" so to speak. Each utility should be asked to submit a list of options they specifically need for operational integration of QFs into their system and a price they think is reasonable to pay for each option. Attached is a more detailed description of this proposal (summarized from our testimony and brief in the Long Run Standard Offer).

I really beleive this approach will work to the benefit of all parties.

JH/og

Enclosures

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Capacity Price Calculations Using a Reliability Adjustment Mechanism

Short-run avoided costs are the sum of two components, the avoided energy cost and the shortage cost. The shortage cost measures the value of reliability to utility customers, and is the basis for the short-run capacity price.

The shortage cost can never exceed the cost of new peaking generation except under very short-term conditions, when the utility needs capacity but cannot build it in time. It can be less if the system is more reliable than the criteria established for construction of new units. Capacity always has some positive value by increasing reliability to customers. However, the amount of that positive value depends on system reliability.

The California PUC bases the capacity value of QFs on the cost of a combustion turbine multiplied by a reliability index based on the ratio of a utility system's Expected Unserved Energy in a given year to an unserved energy target level for that year. This definition, based on sound theoretical considerations, appropriately measures utility system reliability and provides discounts from the full cost of a peaking unit during times when capacity need is lower and increases above that cost in the short term when the capacity need is great.

C--Background
Operational Options for QF Projects Under PURPA

BACKGROUND PAPER ON
A RECOMMENDATION FOR
OPERATIONAL OPTIONS

This proposal for operational options is based upon a belief that if sound business principles are applied in the structuring of this long-run offer, the offer will provide the results the utilities and ratepayers want and result in the QF industry being effectively integrated into the electric utility system.

Because of the regulatory ratemaking process applies to monopoly/monopsony industries such as the electric utilities, behavior is affected through the use of punishment: penalties and sanctions. A utility is awarded its rate of return or recovers cost for a new plant if it performs adequately. If it behaves in a manner considered "imprudent," punishments or penalties are applied. The utility is seldom rewarded for doing "good" but rather "kept in line" through the threat of sanctions. Even in dealings between utilities, there are seldom opportunities for gain since both entities are regulated and involved in balancing the interests of their ratepayers. Again, sanctions are used to try to keep the game honest.

The private business sector provides goods and services based upon incentives. If a good or service is in demand and the buyer is willing to pay a price equal to the producer's cost of production plus some margin of profit then the producer will produce it. If the buyer will only pay a price below the cost of production/service, then no sale takes place. The buyer pays for what he/she gets but does not want to pay more than the product is worth. The seller's decision to sell is based on 1) whether he/she can provide what is desired and 2) whether he/she can get a price for the product which covers costs plus some return on investment.

One other factor comes into play on occasion: the "hassle factor." If the price of the product covers the cost but there is a big hassle (transactions cost) involved in securing the sale or in delivering the product then, the price must be increased to cover the "cost" of the hassle. Conversely, if there is little or no "hassle" involved in either selling or delivering the product, it can be sold for a price much closer to cost.

The purpose of the long run offer is to provide electricity (energy and capacity) to the ratepayers at a fair price. But some other qualities/options may be desired as well (i.e., reactive power, emergency power, real time pricing during minimum load conditions, etc). These are the areas where we believe the concept of incentives can be effectively applied.

IEP proposes a structure where operational options are added to a basic energy/capacity contract under standardized conditions and at a predetermined price. The QF would add options according to the capabilities of the facility assuming the payment is equal to or better than the cost of providing the option.

These options would be standardized. Some operational options like real time pricing on an hourly basis might only be available to projects large enough to have telemetering equipment which could give two-way communication. Other options like reactive power might only be needed in specific geographic locations within a service territory.

IEP recommends that the options have a specific and shorter time period than the contract. Five or ten years would be appropriate. At the end of that time they would be repriced and could be renewed if desired by both parties.

A utility system's operational characteristics change over time. New equipment comes into service, old equipment goes out. Technological advances may result in a type of equipment of service previously unavailable; when gas and oil prices are low, the system may be built or operated much differently to maximize economic efficiency than when gas and oil prices are high. For these reasons, the utility needs flexibility to obtain the types of operational options necessary as situations change. There appears to be no advantage in locking QFs into providing operational options for 30 years which may only be needed for 5 or 10 years. In the same way, if the utility continues to need the option, that contract can be renewed.

First, these operational options should not be limited only to QFs signing new contracts. For example, a utility has a need for reactive power, has worked out the conditions under which it will be delivered, how it will be metered and the price to be paid, there is no reason why any project which had the capability and desire to provide such service not be allowed to add this option to its contract whether the contract is old or new and whether the project is already on line or not yet constructed.

More detailed information on specific operational options are contained in the attached portion of Bill Marcus' testimony in the Long Run Standard Offer hearings and in the attached portions of our brief. IEP presented information on the following seven options in Mr. Marcus' testimony: 1) Availability in Emergencies; 2) Black Start Capability; 3) Power Factor Adjustment; 4) Real Time Pricing; 5) Coordination of Maintenance; 6) Pre-Scheduled Dispatch; and Full Dispatchability. Furthermore, testimony and response to cross-examination by utility witnesses indicate in most cases a sound basis for pricing already exists.

But these are not the only options which could be available. This is one of the advantages to this system. New options can be offered at any time when the utility finds an operational need which QFs might provide or when technical developments provide new opportunities for operational flexibility. New options, like old options, would be available to any QFs qualified to provide the service.

Further, the utility would not have to accept everyone who signed up. If, for example, the utility only needs a specified amount of reactive power, they will put out the option on a first-come, first-serve basis and withdraw the option when the have what is needed. Later if they find they are going to need more reactive power they can reinstitute the option.

The price for these options would be determined in regular PUC proceeding, rates cases, ECAC, or some similar proceeding. The utility will present evidence as to what it would cost them to provide the same option themselves or to purchase it from another utility.

This does not mean we are going to get into a whole series of complex avoided cost proceedings for operational options. Pricing operational optins should be much easier to do than calculating avoided cost. In this case, the utility has a specific need which it would have trouble filling (or incur expenses to fill) if QFs do not provide these operational services. Therefore, there is an incentive to honestly price the option. The QF does not have to provide the service unless he/she wants to (i.e., the price is right) but also has no reason not to provide the service if the price covers the costs plus a little extra. The utility will want to get as close to that crossover point as possible without overpaying. If the underpay, they will get no takers. Therefore, the calculations should be fairly straightforward.

Also, since the amounts of the payments for individual options will generally be low relative to base energy and capacity payments, the level of conflict over these values should also be low.

This program should be fairly easy to administer since the terms, conditions, and prices will be standardized for every project which selects a particular option.

In summary, the advantages of this approach to the long-term offer are the following: First, this approach offers the maximum in flexibility for both the utility and the QF. Assuming the price for each option covers the cost of providing this service, the utility will get as much operational flexibility as QFs are able to provide.

This approach will result in more operational options being selected than might be provided if such options were required by everyone signing a new contract. The reason is that few QFs can provide all the operational options utilities desire. But almost every QF can provide something. If options are limited only to those who are signing a new Standard Offer No 4 and only those who can provide all operational options, there will be few "takers." In addition, a restrictive offer which requires all those signing to provide all operational options will tend to restrict the offer to one or two technologies, thereby limiting system diversity, which could be an extremely important factor to utilities in the future. The IEP approach provides maximum system diversity as well as maximum operational diversity.

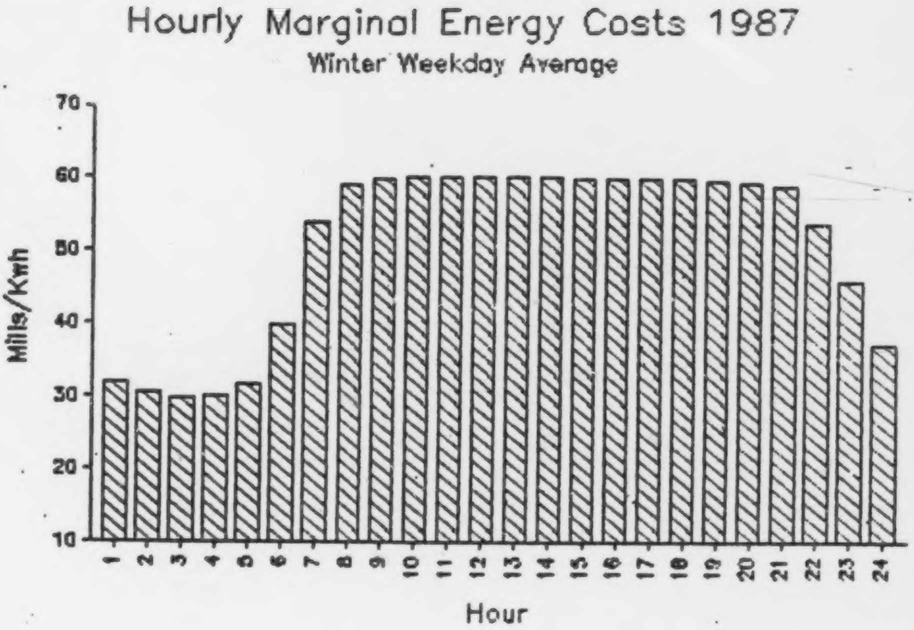
Second, by having options whose component life is less than the 20- or 30-year project life (and/or the energy and capacity contract) and by being able to add options at any time the utility needs something; the QFs are able to change as the utility system itself changes.

Finally, this approach allows the utility to take advantage of new technological developments as the appear without having to jeopardize the capacity and energy requirements of the system.

The approach recommended by IEP allows QFs maximum flexibility for designing their facilities and for contracting. They can offer the utility as much operational flexibility as is technically and economically possible for them to provide.

Some of this flexibility may be available with a negotiated contract but it costs more. Individual operational options may provide small amounts of revenue to the QF though the option is important to the utility. If it is going to require a lawyer six months to negotiate the option, it may not be worth doing it; but if the option is standardized and the value known in advance, it may be worth adding. This is especially important when adding options to an existing contract. Incentives almost always work better than penalties to obtain results from the private sector.

Excerpt From Dave Branchcomb's Direct Testimony In PG&E's 1986 ECAC Proceeding


Hourly Marginal Energy Costs 1987
Winter Weekday Average
Mills/Kwh
70
60
50
40
30
20
10
1
2
3
4
5
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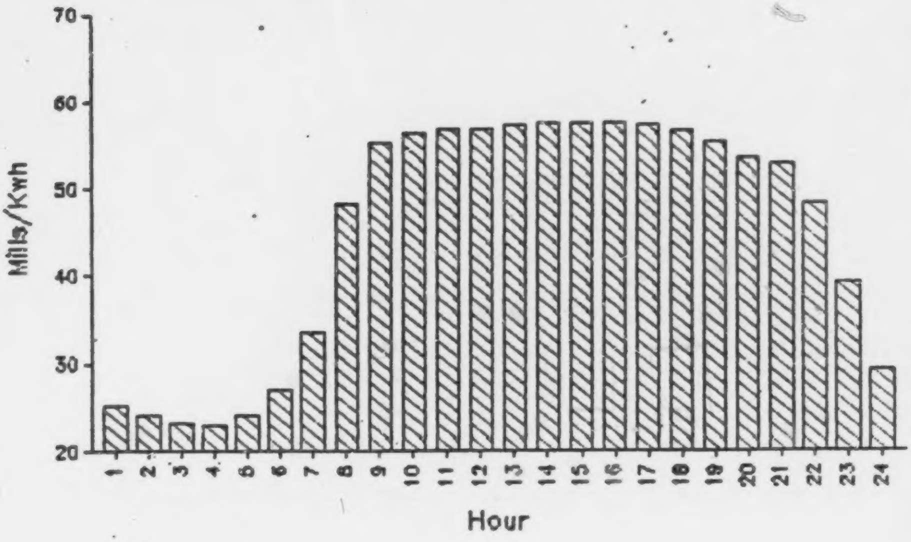
24
Hour

Appendix A

Excerpt From Direct Testimony of William Marcus in Long Run Avoided Cost Proceeding

(P. 4-9 to 4-15)



Hourly Marginal Energy Costs 1987

Summer Weekday Average

SOURCE: ELECTRIC MARGINAL COST MODEL

3-21

4. Contract Options

We now turn to the implementation of contract options which we discussed briefly in the introduction to this chapter.

A. Availability in Emergencies

This section discusses issues related to Contract Terms issue 2b.

If a QF can give a commitment to be available in emergencies and is willing to be penalized for not being available, then it is more valuable, even though a QF who cannot give such a commitment should not be precluded from signing the offer or barred from capacity payments. In certain cases, committing to be available not only risks the penalties of unavailability but adds additional costs to QFs. We can think of two types of interconnection costs which could be incurred in some cases. In the case of Edison, a relatively large QF may choose to interconnect at 220 kV to take the option which would be otherwise unavailable. QF availability in emergencies may under some conditions require waiver of existing utility interconnection standards, in particular changes in over/underfrequency controls may be required to allow the QF to stay on line despite poor power quality so that it can be available to stabilize the system.

A higher capacity payment, coupled with sanctions which take away the higher payment (plus possibly a penalty of some portion of the base capacity payment) if the QF does not perform would implement this option. One potential way to structure the option would be to provide a 10% bonus for availability in emergencies together with loss of the bonus for the preceding 12 months (or since the previous emergency when the QF was available if shorter) in the event of unavailability and utility termination of the option and recovery of some additional payments in the event of repeated failure (e.g., missing three times in a row).

This option would only be available to QFs who would not be automatically shed in the event of a transmission emergency. In Edison's case, it would be QFs attached at 220 kV. For PG&E, we are unsure of the criteria. The option would also not be available to QFs with asynchronous generators because utility power is required to keep them operating and providing high quality power.

B. Black Start Generation

This section relates to Contract Terms issue 2b.

Related to the emergency availability option is black start generation, which would allow the QF to restart itself under the direction of the utility system dispatcher without utility power. Typically, this would involve installing several hundred kW to several MW of diesel generation to be used to start the QF. This is a significant cost to the QF which should be compensated if the utility would find it valuable. It is relatively easy to quantify the cost of standby diesel generation and pay for it over time. This option would be limited to larger, telemetered QFs with firm capacity contracts.

C. Adjustment of QF Power Factor

This section discusses a portion of Contract Terms Issue 2c.

QFs should be given the option to provide reactive power to the utility as needed by the utility. Varying the ratio of real to reactive power is possible for certain QFs, although there is a cost in installing equipment to do so. If the utility needs more or less reactive power under certain conditions, QFs with the capability of supplying should have the option to do so.

Again, the option may be reasonable only for larger QFs with synchronous generation, although it could potentially be used by both firm and as available QFs. Appendix 4-I is an excerpt from a Hawaiian power contract containing reactive power pricing terms for Hawaii Electric Company. The price for reactive power was based on the cost of proxy capacitors at the primary distribution level.

D. Real Time Pricing

This section discusses Contract Terms Issue 1.

While mandatory curtailment should not be required because ratepayer indifference can be preserved by price and because low off-peak prices equate to small amounts of new baseload QF generation, a real time pricing option, if administrable, would be valuable. Such an option could probably be offered on a prescheduled weekly basis to QFs above 1 MW (e.g., with information offered to the QF similar to the following: for all hours between midnight and 6 am for the next week the price shall be 2.3 cents based on the BPA Standard Rate). It is important in this regard to provide information not only on what the price is but information to allow the QF to verify it. Larger QFs (where the transactions costs do not exceed the benefits of real-time prices) could potentially be offered prescheduled prices with a more fine gradation (e.g. daily) or prices using telemetry. The option should have several potential limits on the number of hours of real time pricing which the QF could take (e.g., 1000, 2000, 3000, 4000).

The option can be priced by increasing the prices during off-peak and super-off-peak periods when the real time price does not apply, similar to PG&E's current 1000-hour option in Interim Standard Offer 4, for the fact that some of the lowest priced hours would be removed from the avoided cost calculation. It could be stated in a contract as a fixed (or variable) percentage of off-peak and super-off-peak rates per 1000 hours of real time pricing.

If IEP's method for time-differentiating Period 2 energy prices is adopted, such an option could be readily extended beyond Period 1 into Period 2 if warranted, even if the avoided plant is a baseload unit.

E. Coordination of Maintenance

This section discusses an option not raised in the workshops although related to Contract Terms Issue 1.

Current firm capacity contracts require maintenance in non-summer months and require notice for a QF's annual overhaul. However, utilities can gain a significant energy benefit through closer coordination of annual maintenance schedules to schedule QFs out in low load or high hydro periods. Even with a finer set of time periods, there are some months when avoided costs are lower than others. If a QF can commit to schedule itself out in a low cost month chosen by the utility, its energy value to the utility is greater and should be reflected. Monthly energy cost data produced by PROMOD, GRASS, and similar production simulation models can be used to calculate the price differences as a percentage of the base Incremental Energy Rates or avoided costs. These data can be prorated per day of coordinated scheduled maintenance.

This option should be available to all QFs regardless of size and type of contract.

F. Prescheduled Dispatch

This section relates to Contract Terms Issue 2a.

A prescheduled dispatch option associated with increased energy prices and more certain capacity prices (e.g., dollars per kW-year) should be offered. A QF contract under this option would specify a minimum amount of energy to be taken per year (or possibly on a finer schedule such as monthly), a minimum load (e.g., the QF's minimum load) and a maximum capacity level beyond which the QF could not be dispatched. If the QF had energy constraints (e.g., fuel supply limits) a maximum required annual energy delivery schedule would also be established. The utility would supply a dispatch schedule periodically (e.g., monthly) which the QF would adhere to. There would be some tolerance for non-performance (e.g., due to a reasonable amount of QF forced outage), perhaps associated with ability by the QF to make up energy not delivered at a future time. Any penalties must be commensurate with the additional energy revenue and capacity price certainty. If the risk of penalty is greater than the reward, there will be no takers. One way In Hawaii, where these contracts are common, the penalty structure involves a penalty for the first day (once the tolerance level is exceeded) based on starting up a more expensive unit to run plus a smaller penalty on later days of nonperformance and removal of a portion of the extra revenue for a period such as a week.

Both the rewards and the penalties for such an option must be negotiated on a case-by-case basis to reflect QF's process constraints and minimum loads and the costs and benefits of adding incremental generating capacity (without adding additional energy production) which may be useful for prescheduled dispatch. Telemetry would probably be needed to implement this option. This leads to a de facto QF minimum size level where the benefits from the offer exceed the costs of adding telemetry (if not otherwise required) plus the losses from not being able to sell all the energy one wants and the risks of additional penalties.

G. Full Dispatchability

This section relates to Contract Terms issue 2a.

IEP believes that full dispatchability must be negotiated. There are a number of project-specific characteristics (process and minimum load characteristics, amount of hydro storage which the QF has available, etc.). However, there are several guidelines that we believe can be stated now. Full dispatchability is associated with even higher energy prices than prescheduled dispatch or curtailment options (due to the ability of the utility to reduce QF generation during periods when energy prices are lowest in all time periods). It is also associated with capacity prices in dollars per kW rather than cents per kWh and possibly in higher capacity prices than offered to other QFs. It should only be available to QFs where the costs of the utility controls are less than the benefits of dispatching.

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APPENDIX B

Excerpt From the Independent Energy Producers Association's Brief in Long Run Avoided Cost Proceeding

2. All-or-Nothing Performance Standards Ignore the Fact that the Value of System Needs Can Be Economically Quantified.

Minimum qualifications for Standard Offer 4 which require a QF to mimic a specific utility unit's performance simply in order to receive a contract is an "all or nothing" approach. If a QF misses the minimums by a small amount, it becomes ineligible. Unfortunately, this is not how utility supply planning is done. The "all or nothing" approach assumes that the value of the QF in avoiding a plant is zero with performance below the minimum level and the full value of the plant at or above the minimum level. Economically speaking, the value of all of the options should be quantifiable, not infinitely valuable. (Jurewitz, Tr. 2647-48)

a. Utility "Needs" for Dispatchable Power Change with Fuel Price Forecasts and Are Thus Not Immutable, as Utilities Have Claimed.

There is extensive testimony on the record that the level of forecasted fuel prices can affect the choice between baseload, intermediate and peaking plants. If oil/gas prices are forecast to be relatively high, more baseload is cost-effective; if they are forecast to be relatively low, more intermediate and peaking generation and less baseload is cost-effective. (Kahlon, Tr. 1615-16; Jurewitz, Tr. 2648-49, Hindley, Tr. 3453, Marcus, Ex.

228, p. 2-3) In fact, one can take the same utility system, plug in two different fuel forecasts, and the lower one will have a greater "need" for "dispatchable" generation and a smaller "need" for baseload. (Hindley, Tr. 3453) This economic tradeoff makes it hard for us to see how dispatchability and certain operating characteristics should be required by the utility assuming QFs without those characteristics cannot affect the resource plan. 2/

b. The Value of Many of The Utilities' "Needs" Can Be Quantified.

PG&E and Edison proposed a number of specific operational characteristics that QFs must have in order to sign a final S.O. 4. These characteristics generally include:

1. ability to be curtailed for a significant number of hours per year
2. ability to follow load (dispatchability)
3. availability in emergencies
4. reactive power support
5. minimum annual or on-peak availability standards without which a contract is not available
6. coordination of maintenance

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2. Additionally, the record shows that while Edison believed that it "needs" to keep its baseload percentage down to 40% (Ex. 205, p. VI-3), it inconsistently expected the Southwest, which already has a higher percentage of baseload than Edison, to keep adding more baseload resources, to the point where it would have over 65% coal and nuclear generation. (Ex. 204, Atts. 3 and 4; Cauchois, Tr. 2265; Schoonyan, Tr. 2849)

PG&E added a whole laundry list of additional detailed operational characteristics including:

a. Ramprate (MW/hour)
b. Hot start-up time (hours)
c. Coldstart-up time (hours)
d. Scheduled maintenance (both duration and cycle in days)
e. Equivalent forced outage rate (%) (considers both partial and full forced outage)
f. Minimum load at which a plant can operate without shutting down (expressed as a % of capacity) (Ex. 219, p. PDH-30) 3/

In fact, all of these characteristics are not invaluable to the electric utility but, at least in principle, quantifiable in some way. (Jurewitz, Tr. 2647-48, 2681; Mitchell, Tr. 3215-16; Marcus, Ex.228, pp. 4-9 to 4-15) We will examine the valuation of individual options/requirements in some detail.

i. Curtailment/Real Time Pricing/Dispatchability

Assigning a value to curtailment or dispatchability from an energy perspective is not difficult in concept. We start with the premise that if off-peak prices factored in a reasonably accurate amount of economy energy at the margin, then other than for conditions of hydro spill and negative avoided cost where the utility has the ability to curtail QFs under current contracts, the utility would not care if the QF were or were not turned off. This position was agreed to not only by QF witnesses (Marcus,

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3. On cross-examination, Mr. Hindley retreated somewhat from his position that all of these items are mandatory, stating only that "it's possible" that a QF who missed one or more of this list should not be given a final S.O. 4 contract. (Tr. 3394-95)

Ex. 228, p. 4-7), but also by Edison witness Schoonyan. (Tr. 2829-31) If a peaker or intermediate unit were avoidable, the off-peak price would, under IEP's proposal, be based on short-run marginal cost. If a baseload unit is avoidable, its fuel costs would be low, and curtailment would therefore be unlikely to occur. Furthermore, IEP would also time-differentiate the price for a baseload unit. Therefore, if a QF s is not curtailable or subject to real-time pricing, its value is no less than the average short-run marginal energy cost during off-peak periods.

Staff recognized this fact from the point of view of system operations. Baseload QFs would avoid utility start-ups of units, (Tr. 1577) and would avoid variable O&M (Tr. 1579). Two systems, equal in all respects except that one had an additional CT and the other did not, would have the same short-run marginal energy costs. (Ajello & Kahlon, Tr. 2035-36) However, PSD would instead propose to pay QFs a price less than full avoided cost (based on system lambda, which leaves out these components of avoided energy cost) if a CT were avoided and they would not agree to be curtailable. (Kahlon, Tr. 1576; Ex. 201, pp. 29-30) This position is unreasonable.

The higher price that should be paid to a curtailable QF thus does not come from intrinsically greater value during the hours when the QF subject to curtailment or real time pricing actually produces power or to its lesser value during other time periods than PMOC. It instead arises from an inconsistency in the method for calculating short-run marginal energy costs between the current method and the assumption that the QF is subject to real time prices or curtailment. The current practice calculates short-run marginal energy cost based on hypothetical QF availability in all hours. If a QF is subject to one of these provisions, the QF is not producing power or is being paid using a real-time price in the lowest cost hours of the year or the time period. A short-run marginal cost payment based on all of the hours of the year is thus too low. The energy value of curtailment, dispatchability, or real time pricing is a price adjustment in the non-curtailed hours to a higher price which excludes the curtailed hours, similar to PG&E's curtailment option in Interim S.O. 4. This point was recognized in the direct and cross-examination testimony of both Mr. Marcus and Mr. Hindley. (Marcus, Ex. 228, pp. 4-12 to 4-13, Tr. 3993-94; Hindley, Ex. 219, pp. 28-29, Tr. 3417, Tr. 3438-39; Mitchell, Tr. 3240)

Other attempts to find added value for prescheduled dispatch or full dispatchability were less fruitful, but even those attempts show that its value is not infinite and not the full value of the plant. Edison labored long to show why dispatchability was enormously important. However its best argument was if a resource were non-dispatchable, it could result in rejection of economy energy, (Ex. 205, p. III-3), a factor which can be controlled through time-differentiated pricing, as Mr. Schoonyan admitted. (Tr. 2829-31) Mr. Schoonyan also recommended a 2 percent cost reduction for full dispatchability over partial dispatchability, based on the ability to load oil/gas units at their optimal points. (Ex. 205, p. III-3, Tr. 2976) However, given day-to-day uncertainties of demand, uncertainties in economy energy availability, and the small size of QFs which enables their performance to be statistically estimated, (Tr. 2832-34) we are uncertain whether prescheduling QFs actually has that value. As Mr. Schoonyan testified:

> We were not able to quantify what value at this point in time--how should I say it--a warm feeling that the operator would have on a day prior to the commitment of generation. (Tr. 2832)

ii. Availability in Emergencies

The utilities' testimony and data responses clearly show that the value of availability in emergencies is also not the full value of the utility plant although the quantification of this value produced a number of disparate methods and calculations. PG&E's response to interrogatories state that QF availability in emergencies was "mandatory" but that it could not answer the question regarding quantification, nor could it clearly define what an emergency was. (Ex. 228, App. 4-E)

Edison's data response to IEP contained in Exhibit 211 indicates that as of December 5, 1985, Edison had not figured out how to quantify availability in emergencies. (Ex. 211, p. 6, Response to Question 6c) By the time Mr. Schoonyan had prepared his testimony, he had devised a methodology based on increases in spinning reserves to cover emergency availability. In his view, a 3% increase in spinning reserves would cost $10 million. Spreading this figure over 600 MW of QFs would give about $15/kW-year. (Ex. 205, pp. II-4, III-1, Tr. 2818-19) Implicit in this assumption is the contention that extra spinning reserves would have to be maintained for approximately half of all of Edison's QF generation. (Tr. 2818-19) He testified however, that after adding 600 MW of QFs, Edison has not changed its spinning reserve practice, (Tr. 2820) and that any change in spinning reserves would also be caused by high levels of imported power from outside Edison's service area rather than solely the impact of QFs. (Tr. 2819) Finally, following through on Mr. Schoonyan's logic and Edison's QF success rate, Edison would require spinning reserves of about 20% when its QFs reach full development.4/ We find this figure totally unsupported. Mr. Schoonyan also speculated that it could lead to Edison's loss of interconnected support and ability to purchase economy energy (Ex. 205, p. II-5) but could not state when or if such an event would happen and indicated that it would require "flagrant" abuses to achieve this result. (Tr. 2822-23)

Given the discussion below which indicates that Edison's own system design and operation is one of the causes of unavailability of QFs in emergencies, we would expect Edison to try to change the factors under its own control if the situation ever were to reach the point where interconnected operations were threatened. Furthermore, if this extrapolation from Mr. Schoonyan's testimony were in fact true, and Edison would not then change its operating practices to allow low voltage QFs to stay on line during

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4. Edison predicted about 2800 MW of QF generation. (Ex. 205, p. VI-8) At 3 percent extra spinning reserves for each 600 MW of QFs (Tr. 2818-19) we calculate 14 percent extra spinning reserves, or 21 percent total spinning reserves counting the 7 percent existing reserves (Ex. 205, p. II-4).

emergencies, we believe that the extra expenses would be clearly imprudent expenses that ratepayers should not bear given the spinning reserve costs cited by Mr. Schoonyan. However, the very fact that Mr. Schoonyan attempted to quantify this factor is an admission that its value is not incalculably high.

SDG&E's quantification was based on the cost of purchasing emergency power from the power pool. (Ex. 217, Response to Question 6c) This response seems to suggest that SDG&E does not believe that all of the dire consequences outlined by Mr. Schoonyan with regard to interconnected operations are likely to occur or need to be combatted with increased spinning reserves. SDG&E also indicated that the value of availability in emergencies is related to the frequency of emergencies, and agreed that SDG&E had had no system emergencies in the last five years. (Ex. 217, Response to Question 3A; Tr. 3217-18)

iii. Voltage Support

Voltage support was one of the easiest items to quantify, although its value may be limited to some specific geographic areas and voltage levels. The cost of voltage support involves proxy capacitors. (Marcus, Ex. 228, pp. 4-11 to 4-12, App. 4-I; SDG&E, Ex. 217, Answer 5c; Schoonyan, Tr. 2814-16) Under PG&E's current interconnection standards (PG&E Rule No. 21), and conformed contract language proposed for all utilities (Ex. 210), QFs must be able to operate between 90 percent leading and 95 percent lagging. Only operation outside these levels is at issue. (Branchcomb, Ex. 233, p. 36)

At issue is whether utility plants provide all the reactive power needs of the utility system. Utilities claim that they do. However, reactive power can only be transmitted for short distances. (Ex. 205, p. II-5) Power from facilities outside Edison's service territory does not support voltage. (Tr. 2809) 5/ Furthermore, QFs may not be able to provide reactive power at the high voltages at which utilities are interconnected but may be able to provide needed voltage support at lower voltages, where the only alternative is a utility capacitor. (Schoonyan Tr. 2816, Marcus, Tr. 3889-90, 3992)

Estimates of the value of reactive power are in the $10 to $20 per kilowatt range. (Ex. 205, p. III-1 as corrected) However, it should be noted that this figure, when multiplied by a utility's economic carrying charge rate (on the order of 12 percent) amounts to about $2 per kW-year. Mr. Branchcomb estimated that the whole issue, whether valued from the point of view of loss of QF output as he proposes or of a proxy capacitor, as IEP proposes, is about 1 mill per kWh. (Tr. 4506-07)

iv. Coordination of Maintenance

Requirements that QFs coordinate maintenance with utilities have also been proposed. Again, there are methods for placing a value on this coordination. Firm QFs already are prohibited from taking substantial amounts of maintenance in summer peak periods. (See e.g. PG&E Interim SO4, Appendix E; a similar clause is preset in SO2), and as-available QFs are unlikely to want to do

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5. PG&E did not know whether plants outside its service area can or cannot support voltage. (Crisick, Tr. 3543)

so given that their capacity payments are substantially paid during those periods. IEP testified that certain months, particularly in the spring, may have lower marginal energy costs than others and that maintenance during those periods rather than other periods would result in quantifiable cost savings to the utility (because those lower cost periods are factored into average short-run marginal costs). (Ex. 228, p. 4-13) However, again this factor is quantifiable, not an "all or nothing" item.

v. Minimum Availability of QF

All of the utilities have proposed minimum availability standards for QFs signing the final S.O. 4. However, their rationales for these standards on an all-or-nothing basis rapidly collapsed. Under cross-examination, Mr. Hindley admitted that under PG&E's proposed availability standard of 80 percent, a QF with 75% availablity would be ineligible for the contract but would in fact have a capacity value approximately 75/80ths as much as one with 80% availability. (Tr. 3396-97) Mr. Mitchell made the same statement with regard to SDG&E's proposed 60% availability standard. (Tr. 3238) 6/ Therefore, in general, we believe that

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6. Under SDG&E's proposed payment option, where the entire capital cost (capacity and ERFC) of the plant is paid in dollars per kilowatt, (Ex. 216, pp. 37-38) some type of performance standard is probably necessary because of the enormous risks that SDG&E's proposal places on ratepayers by departing from the cardinal principle of QF pricing of paying for performance. However, that fact is a reason for rejecting SDG&E's proposal and adopting IEP's payment option proposals (discussed below) which are fairer to ratepayers, not a reason for instituting performance standards. Mr. Mitchell himself testified that payment in cents per kWh would result in an automatic price reduction if the QF failed to perform, without specific standards. (Tr. 3239)

compensation in cents per kilowatt-hour will fairly pay QFs their value without minimum all-or-nothing standards. 7/

vi. SDG&E's Auction Proposal, While Flawed, Quantifies Many of the Operational Attributes that PG&E and Edison Find Invaluable.

We analyzed the point structure recommended by SDG&E in its bidding proposal (Ex. 216, pp. 24-28), and converted the points recommended by SDG&E into equivalent percentages of avoided cost and determined that SDG&E has, in fact, attempted to place a value on many of the operational characteristics that Edison and PG&E testify are mandatory and virtually invaluable. The values assigned by SDG&E are shown below:

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7. We have heard in this proceeding that firm capacity options under SO2 and Interim SO 4 were based on dollars per kilowatt-month. However, a close reading of the contract indicates that the payment is proportional to the QF's actual kWh output with the exception of the range between 80 and 85% capacity factor and the partial exception of hydro QFs. (See, for example, PG&E, Interim SO 4, Appendix E) The current structure is thus basically a payment in cents per kWh because it varies with QF output.

Option	Points	Equivalent % of Avoided Cost
Dispatchability	100	10 %
Curtailment		
1000 hours	25	2.5%
2000 hours	40	4 %
3000 hours	50	5 %
Availability 80% in peak hours of peak months	10	1 %
Coordination of maintenance	10	1 %
Reactive power support	5	0.5%

While SDG&E has quantified the value of these items, by treating them as points on the RFP, SDG&E implicitly views QFs who do not have these attributes as worth less than base avoided cost. This is incorrect, even within the context of bidding. As shown in Sections i and iv supra, the energy value of dispatchability, curtailment, and coordination of maintenance is an energy value above the ceiling price. The base avoided cost, which is directly calculated from PMOC off-peak (if an intermediate unit) or time-differentiated based on PMOC (if a baseload unit) assumes in the PMOC calculation that the QF will operate in all hours. Curtailment, dispatchability, and coordination of maintenance all reduce operation predictably in the lowest cost hours. A price (or time differentiation) based on the average PMOC does not reflect the fact that QFs who curtail output avoid a PMOC higher than average. (Tr. 3990, 3942-43, 3954) These items should therefore not be points on the RFP, which undervalues them, but adders to the base avoided cost.

The extra points for 80% availability in peak periods would be double-counting under the IEP proposal, where firm capacity is offered a higher price than as-available. Reactive power support, as discussed in Section iii supra, may or may not be provided by a utility plant and affects local areas and specific voltage levels. It is therefore a system need better treated as an adder.

In sum, the SDG&E quantification convincingly refutes PG&E's and Edison's testimony. Further, with the exception of 80% availability in peak hours of peak months, these values, if shown to be reasonably quantified, could be used to develop the operating option adders addressed in Section III below.

3. There Is Virtual Unanimity That Baseload QF Generation Can Avoid Utility Generation of Other Types.

IEP has taken the position throughout the proceeding that QFs can avoid any type of utility generation and that even if QFs operate in a baseload mode, ratepayers can be made indifferent through proper pricing mechanisms which only pay the QF a price based on the capital and operating costs of the avoided plant during the projected hours of operation of the utility plant.

The utilities, and to a lesser extent Public Staff, have taken the position in direct testimony that if a QF does not look like the avoidable plant, particularly if that plant is dispatchable, it cannot cause the plant to be avoided. (Ajello & Kahlon, Ex. 201, pp. 20-21, Hindley, Ex. 219, pp. PDH-19, PDH-30, Schoonyan

III. IEP'S PROPOSAL FOR OPERATIONAL OPTIONS PROVIDES A FLEXIBLE APPROACH TO MEETING UTILITY SYSTEM NEEDS WHILE RECOGNIZING AGGREGATE VALUE.

Instead of supporting mandatory performance requirements that all QFs must meet, IEP supports a set of options or riders that would provide a base energy and capacity price and compensate QFs for providing operational characteristics beyond base energy and capacity prices which have a value to the utility. These riders would generally have standard prices, with the exception of complex options for prescheduling and full dispatchability where there would be standard guidelines, but the price would be based on the individual QF's operational parameters, such as its required minimum load. The standard prices and guidelines would reduce transaction costs and hassle associated with negotiating with utilities to provide such options. (Ex. 227, p. 12)

Dr. Hamrin testified that this process could actually provide more operational options being selected than if the utility required all QFs to operate very similarly to the avoided plant.

> [F]ew QFs can provide all the operational options utilities desire. But almost every QF can provide something. If options are limited only to those who are signing a new Standard Offer 4 and only those who can provide all operational options, there will be few "takers". (Ex. 227, p. 10)

The testimony of Mr. Marcus discusses the details regarding implementation and pricing of seven specific options which IEP believes could be implemented. We will discuss these specifics below in more detail.

A. IEP's Seven Specific Options Recognize Potential Utility Needs and Provide Accurate Pricing Guidelines.

IEP recognized seven areas where QFs could potentially provide additional operational flexbility:

a. Availability in emergencies

b. Black start capability

c. Reactive power or voltage support

d. Real-time pricing

e. Coordination of maintenance

f. Prescheduled dispatch

g. Full dispatchability

Mr. Marcus offered a general method for pricing a number of these options as adders to basic avoided cost, although, as Dr. Hamrin testified, the options would be priced individually by the utility based on its cost of supplying them.

On the energy side, real time pricing, coordination of maintenance, prescheduled dispatch, and full dispatchability all are associated with higher prices than base avoided cost. As explained in Section II.C.2.b, subsections i, iv, and vi, these items create a higher avoided energy cost because the PMOC on which prices are based or time-differentiated presumes operation in all periods, including periods of lower prices when QFs would be dispatched downward, curtailed, or on coordinated maintenance. As Mr. Marcus testified, "you would be underpaying somebody if you calculated a price based on [operation in] all of the off-peak hours and then curtailed them in the lowest ones."(Tr. 3990; cf. also Ex. 228, pp. 4-12 to 4-15; Tr. 3942-43, 3954, 3994)

For capacity prices, we would provide additional price certainty through payments in dollars per kW-month, and possibly greater payments for dispatchability and prescheduling. (Ex. 228, pp. 4-14 to 4-15) SDG&E, at least appears to agree that the dollars per kW-month pricing for dispatchability and prescheduling is reasonable. (Ex. 216, p. 36) IEP justified the higher price than a full CT on the interaction between the size of the QF (causing it to avoid more than 1 MW of utility generation per MW of QF generation at the utility's CT availability factor) and the quality of the QF's generation due to dispatchability or prescheduling. (Tr. 3958-59)

Quantification of black start generation value, if required, would be based on backup diesel or other generators. (Ex. 228, p. 4-11) Reactive power support beyond that required to maintain voltage balance for the individual project, which would only apply for operation of the QF outside the range in the current conformed contract language (Ex. 210) would be either based on reduction in QF output (which would be similar to reduction in utility output not quantified in fuel and O&M costs of the utility powerplant), as proposed by Mr. Branchcomb, (Ex. 233, p. 36) or on a proxy capacitor. (Ex. 228, p. 4-11, App. 4-I) In the specific case of California utilities, both values would be approximately equal at about 1 mill per kWh, according to Mr. Branchcomb. (Tr. 4507-08) SDG&E's RFP quantification yields a somewhat smaller number of about 0.25 mills per kWh (0.5 percent of a hypothetical 5 cent real avoided cost). (See Section

II.C.2.b.vi supra) IEP presented one option to quantify value of availability in emergencies, (Ex. 228, p. 4-10) but there may be others. (Tr. 3951-52)

The Commission should adopt general guidelines regarding this quantification process and request specific numbers in the compliance phase. An example of such a guideline would be that the energy values of real-time pricing, dispatchability, prescheduling, and coordinated maintenance are based on the difference in PMOC between all-hours operation and operation only in uncurtailed hours.

As Mr. Marcus explained, prices for these options could be stated as a ramped up forecast, as a percentage of avoided energy cost, or, if it were a firm capacity-related option, fixed and levelized. (Tr. 3941)

B. IEP's Option Proposal Provides Flexibility for Changing System Needs.

IEP would offer these options to QFs at the discretion of the utility. If an option is not needed, it would not be offered. If an option is needed for a limited number of MW or in a limited geographical area, (as black start generation or voltage support is likely to be) it would only be offered to that number of MW (on a first-come-first-serve basis) and/or to the affected area. (Ex. 227, p. 8, Tr. 3717-18) Some options (e.g., real time pricing, prescheduling, coordination of maintenance, and full dispatchability) would be unlikely to have MW limits given utilities' statements regarding the need for them. (Tr. 3956) Some options may have other limits on who could take them (e.g., only firm QFs or QFs above a certain size or interconnected at a certain voltage). (Ex. 228, pp. 4-10 to 4-11, 4-14 to 4-15) As a result, IEP is building reasonable flexibility for the utilities into the option process.

Further flexibility is created by IEP's proposal for pricing the options. Options may be withdrawn or repriced prospectively for new contracts in any relevant case. The initial contract rider will contain a price formula for the option which applies to that contract for 10 years. At the end of the 10 years specified in the QF contract, the option may be withdrawn by the utility if no longer needed or repriced. If the option is not withdrawn, it is renewable at the new prices at the QF's option. Subsequent to the initial 10-year term, the withdrawal, repricing, and renewal process would occur at five year intervals. The utility may create new options in relevant cases if operational, technical and economic conditions warrant. (Ex. 227, pp. 6-7; Ex. 228, p. 1-5)

C. IEP's Option Proposal Is the Only Proposal that Could Be Applied to Existing Contracts to Integrate These QFs into the System More Effectively.

The options proposed by IEP have the further advantage that they are the only mechanism proposed in this proceeding that could assist in the provision of operational options in existing and future SO 1-3 and Interim SO 4 contracts. IEP proposes that the options be developed as contract riders that could be added to existing standard offers or negotiated contracts, with a minimum of negotiation, as well as applying to final SO 4 contracts. (Ex. 228, p. 1-4) Such a set of optional riders would also reduce the "hassle factor" for the utility in obtaining operational flexibility from existing QFs and would avoid the problem that QFs would find it risky to reopen existing contracts. Ours is thus the only proposal that would encourage the conversion of existing contracts to supply utilities with valuable operational characteristics.

APPENDIX C

American Wind Energy Association

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PROGRESS REPORT ON WIND ENERGY IN THE UNITED STATES

June, 1986

The use of wind energy to produce electricity, largely confined to a few rural homesteads until 1981, has grown dramatically in the last five years.

Today, dozens of generating stations called "windfarms," in which hundreds of wind electric turbines are installed, are producing power in three major development areas in the state of California.

At the beginning of this year, more than 13,000 wind machines were in place in the windfarms, with a total peak capacity of about 1,100 megawatts (MW), or more than an average-sized nuclear power plant. Yet those machines were installed in just over four years, or less than half the time required for a nuclear facility.

This year, the American Wind Energy Association (AWEA) predicts, those wind turbines will generate 1.5 billion kilowatt-hours (kWh) of electricity, enough to serve the residential electric needs of a city the size of San Francisco. If oil were burned to produce that much power, 2.5 million barrels would be required.

While 2.5 million barrels is still only a tiny fraction of the energy America uses, wind energy's potential is large -- some studies have placed it as high as 40% of current electricity demand -- and the production of the windfarms has been more than doubling each year:

Year	MW Installed	kWh Produced
1981	7	10,000
1982	64	4,800,000
1983	230	46,600,000
1984	520	188,100,000
1985	1,100	662,000,000
1986	1,300 (est.)	1,500,000,000 (est.)

At the same time, excellent progress has been made improving the reliability of wind turbines and in bringing down the cost of the power they produce.

Pacific Gas & Electric (PG&E) Co., the nation's largest

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investor-owned utility, estimated in a study of thousands of wind turbines completed early this year that when all the production numbers for 1985 were added up, the average wind turbine would have produced more than six times as much energy as in 1982, just three years earlier.

In the same study, PG&E estimated that with current technology, a windfarm could be built which would produce power for 6 ¢/kWh, a price which would make wind electricity competitive with oil-fired power plants. A more recent case study by U.S. Windpower, a manufacturer of wind turbines, suggests that the recent drop in interest rates has made wind energy cheaper, and that a price of less than 4 ¢/kWh is now attainable.

These numbers are consistent with several studies by the California Energy Commission which project that wind and hydro power will be the cheapest generating options for utilities by the year 1990.

The surprisingly swift growth of this industry, and its emergence as a major new energy option for the United States, rest on two foundations: the energy tax credits and the Public Utility Regulatory Policies Act of 1978 (PURPA).

The energy tax credits have made it possible for the industry to obtain investment money in spite of the tremendous risks inherent in a brand new technology. PURPA, by guaranteeing that the electricity the windfarms produce can be sold for a fair price, has helped to reduce those risks and to neutralize the otherwise overwhelming competitive advantage the electric utilities would have.

Because of these two visionary pieces of legislation, the United States leads the world by a wide margin in successfully developing the potential of wind energy as a source of electric power.

The CHAIRMAN. Thank you.

Mr. Nicholson.

STATEMENT OF WILLIAM J. NICHOLSON, CHAIRMAN, ELECTRICITY COMMITTEE, AMERICAN PAPER INSTITUTE

Mr. NICHOLSON. Thank you, Mr. Chairman. My name is William J. Nicholson, manager of Corporate Energy Services, Potlatch Corp. I am chairman of the electricity committee of the American Paper Institute.

API is the trade association for the bulk paper and paperboard industry in the United States. The paper industry is the Nation's leader in cogeneration and self-generation of electricity, accounting for about 35 percent of the total installed U.S. cogeneration capacity, in the neighborhood of 7,500 megawatts. This industry has been cogenerating since the early 1900's because the technology accommodates by the needs of the paper manufacturing process for both electricity and steam.

The reliability of cogenerated power from paper mills is quite high. The pulp and paper mills operate 24 hours a day, 355 to 360 days a year. The availability of cogenerated power exceeds 90 percent.

This compares quite favorably with the average utility generating unit availability of 70 to 75 percent. The paper industry satisfies about 44 percent of its own electricity needs through cogeneration, so you can see that reliability in this industry is vital.

The paper industry is the third largest purchaser of electricity among the manufacturing industry, with an annual bill exceeding $2 billion. We seek to ensure the utilities, as purchasers of cogenerated power, are acting in the best interest of their ratepayers; to provide adequate and reliable supplies of electricity at the least cost.

I am here as a ratepayer, as well as a cogenerator type.

The paper industry has been very supportive of the PURPA and its objectives since its enactment in 1978. Prior to 1978, a combination of economic and regulatory constraints and utility opposition to industrial generation of electricity had discouraged many paper companies from cogenerating power in excess of their own needs, and in some cases, from cogenerating power at all.

PURPA opened the door to greater development of energy efficient cogeneration and use of renewable fuel, such as wood residues, to generate electricity for the good of the public. It is especially important due to the high cost of fuel and other difficulties in utilities, in bringing in large generating units online at cost-effective rates.

Our major legal efforts in support of PURPA and the FERC regulations issued in 1980 were in two cases, one of which API and FERC brought to the Supreme Court.

The Supreme Court has now upheld the constitutionality of PURPA and the validity of FERC's regulations.

With the major uncertainties about PURPA resolved in the court, in 1983, the paper industry has increased its electricity production, using cogeneration, by about 26 percent, from 1982 to 1985.

API estimates there is a further 30 percent in its cogeneration capacity in the next 5 years, assuming that PURPA remains in effect without amendment.

We believe that the programs envisioned by the authors of PURPA are only now beginning to be realized. I would like to cite two examples of how. First, the amount of power sold by qualifying facilities has increased dramatically.

In our industry, the increase was about 400 percent in the 1982-85 period, but that also represents a figure of only a few hundred megawatts because we serve ourselves in many cases.

Second, the avoided costs are coming down in most States. As more cogenerators come online and the need for a utility to powerplants is deferred to the future. This is certainly true in the State of Idaho, where my company is founded and has significant operation.

Now that the Federal PURPA law is more certain, we find the battles are being fought again at the State level. The paper industry recognizes the State's authority to implement the law within the framework of PURPA.

I mentioned a moment ago the phrase avoided costs. The phrase is perhaps the focal point for much of the discussion of PURPA and the subject of much controversy. They have been described as unfair to ratepayers.

Avoided cost is what it would cost the utility in question to either generate or buy from another utility the kilowatts of electricity that are being purchased from the cogenerator, and properly calculated, cannot cost more than other power that utilities could obtain.

I might add that if indeed one was to not offer avoided costs and required something less than that, the ratepayers would be injured by that process.

In practice, most utilities sign electricity purchase contracts at levels below the utility's avoided cost for the life of the contract. Although there is no guarantee that the payment to a cogenerator will be lower than a utility's alternate cost in a single hour or single day, over the longer term, ratepayers will benefit from prices paid to the cogenerators.

These ratepayers will avoid ratebase effects of new, large, expensive baseload capacity, and in many cases will be paying for cogenerated electricity at a rate that is even below the utility's running cost.

Issues related to PURPA implementation beyond avoided costs need to be addressed. They include such things as sanctity of the contract. Once a contract is signed, agreed to by the buyer and seller, and once it is reviewed and approved by the State public utility commission, it is valid and ought not to be breached by the seller, the buyer or the regulatory commission. To do so would jeopardize the financing of cogeneration projects and, indeed, the viability of the projects themselves.

The ratepayers would be faced with the loss of many potentially economic cogeneration resources.

An issue in some States is the utility reimbursement for power purchased at avoided costs from cogenerators. The paper industry maintains that a utility, acting in a prudent manner as the agent for its ratepayers should be reimbursed by the ratepayers for the purchase of this power.

As long as the cogeneration contracts are in accordance with the avoided cost approach, since such contracts must be approved by the State commission, this reimbursement will add no additional burden to the ratepayer. In fact, they should realize savings.

Federal rules permit, but do not require, State commissions to direct utilities to enter into levelized payment arrangements for the purchase of cogenerated energy. Levelized payments are payments that are fixed levels for the life of the long term contract.

The level selected is at or below the utility's avoided cost for the life of the contract, although it may be somewhat higher in the expected avoided costs in the earlier years in the expected avoided costs in the later years.

Use of levelized payments assures that the ratepayer of cost-effective development in cogeneration resources in the long term.

Simultaneous purchase and sale of electric power, which was upheld by the Court of Appeals, is an option that allows cogenerators to sell power at the avoided cost rate and purchase power for their plant at the regular retail rate. In the simplest sense this looks like a windfall for the cogenerator who buys low and sells high.

But, in the more complex world of power, this is not the case. First, the price of power sold to the cogenerator by the utility represents the cost of many utility generating stations, its overhead, fuel costs and other factors. The price of power the utility purchases from cogenerators is based on avoided costs, which I have discussed.

If simultaneous purchase and sale arrangements did not exist and instead a cogenerator used all of its power internally, its demand on baseload would decline. The utility would sell less power and its fixed costs would be allocated to the rest of the ratepayers, increasing their costs.

Using simultaneous purchase and sales, a cogenerator can develop power at cost effective prices for the ratepayer even if the average utility price of power will not support cogeneration to serve its own load. Backup power for cogeneration plants is needed when a cogeneration facility is temporarily shut down for maintenance or repair.

There can be no industrial cogeneration without backup power. It is included as one of the assurances given by PURPA, Alcon, the third-party financed and owned cogeneration, was denied standby and backup power by the local utility if the user of the cogenerated steam and electricity was a separate corporate entity.

It is troublesome that FERC chose to let the way a cogeneration project is financed become a barrier to the proper implementation of PURPA, especially when PURPA clearly sought to ensure cogenerators backup time.

FERC is going to rehear the case, and we look forward to the reversal.

The paper industry continues its opposition to the removal of the present 50 percent cap on utility ownership for cogenerators qualifying under PURPA. Utilities can presently own as much of a cogeneration project as they choose. However, if they exceed the 50 percent limitation on the project, they can no longer qualify for PURPA benefits.

This limitation works to ensure that utilities do not use their undisputed market power to dominant cogeneration development to their sole corporate benefit and to the detriment of ratepayers and non-utility cogenerators.

We believe that this limitation on utility ownership should not be changed.

The last issue is access to the transmission network. We, in the paper industry, know that the issue of wheeling has been the subject of some heated debates during the consideration of legislation on relicensing of hydroelectric facilities.

During testimony on that bill before this committee, our industry stated that although we favor wheeling as a concept, we felt it was inappropriate in the more narrowly drafted hydro bill, which we supported.

We support wheeling as a means to supply lower cost power to utilities other than the local utility of a qualifying facility.

Currently, unless the local utility agrees to deliver power to others through the use of its transmission system, qualifying facilities have no other market. Qualifying facilities are limited to a single market for their product, that is, the local utility. In many cases, additional facilities will not be constructed.

The paper industry supports wheeling as a means of supplying cogenerated power to utilities other than the local utility, thus providing a greater benefit to ratepayers.

In conclusion, Mr. Chairman, PURPA is basically working. In a few short years, it has already provided benefits to ratepayers and will continue to do so.

There are still questions about PURPA being addressed at FERC and at the State level. We urge that the impediments to PURPA be removed so that full implementation of the law can be achieved.

Thank you.

[The prepared statement and a subsequent submittal of Mr. Nicholson follow:]

STATEMENT

OF

WILLIAM J. NICHOLSON

REPRESENTING THE

AMERICAN PAPER INSTITUTE

BEFORE THE SENATE COMMITTEE ON

ENERGY AND NATURAL RESOURCES

ON

THE IMPLEMENTATION OF THE PUBLIC UTILITY

REGULATORY POLICIES ACT

June 3, 1986

STATEMENT OF THE AMERICAN PAPER INSTITUTE TO THE SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

June 3, 1986

I appreciate the opportunity to appear before the Senate Energy and Natural Resources Committee to express the views of the American Paper Institute during these oversight hearings on the implementation of the Public Utility Regulatory Policies Act of 1978.

My name is William J. Nicholson. I am the Manager, Corporate Energy Services, for Potlatch Corporation. I am testifying today on behalf of the American Paper Institute (API), the national trade association of the pulp, paper and paperboard industry. API consists of approximately 175 manufacturers which produce over 90% of the nation's pulp, paper and paperboard. I am the Chairman of API's Electricity Committee and a member of the API Energy Council, which directs the association's energy activities.

INTRODUCTION

The pulp and paper industry is the nation's leader in cogeneration and self-generation of electricity, accounting for about 35% of the total installed U.S. cogeneration capacity - approximately 7500 megawatts of electricity. The industry is well suited for use of cogeneration technology since it has both high electrical and thermal demands for energy, easily addressed by cogeneration operations. In the most common cogeneration application in the industry, high pressure steam is expanded through a turbine to generate electric power. The steam is then extracted or exhausted from the turbine at lower pressures and temperatures to be used for mechanical drives, pulping, bleaching, drying, and space heating.

The industry's use of this low pressure steam, normally condensed in conventional utility generating facilities, makes the paper industry cogeneration process two to three times more energy efficient overall than the steam condensing based electricity generation at utility generating facilities. In addition, the reliability of cogenerated power from paper mills is very high. Since steam is required to operate mills 24 hours per day, 355 to 360 days per year, and proven technologies are used, pulp and paper mills have a cogeneration availability exceeding 90%. This compares quite favorably with the average utility generating unit availability of about 70-75%. Approximately 44% of the paper industry's own electricity demand is met through its cogeneration operations.

The paper industry is the third largest purchaser of electricity among manufacturing industries in the United States. Its annual bill for purchases of this form of energy exceeds $2 billion. Therefore, it is in the interest of the paper industry for electric utilities to provide an adequate and reliable supply of electricity at the least cost to the ratepayer. This interest, we believe, is shared with all ratepayers. Cogenerated power has an important role to play in meeting this national objective.

BACKGROUND

The paper industry has cogenerated power and self-generated hydropower since the early 1900s. Potential development of additional cogeneration capacity, however, was stymied prior to enactment of PURPA since many paper companies wishing to sell any electric power, not just cogenerated power to the grid, frequently met opposition from the large utility companies which offered only dump rates for the power. Pulp and paper companies had little incentive to cogenerate power in excess of their own needs and in some cases had little economic incentive to generate power at all.

In light of institutional and economic constraints, the necessary investment of capital and manpower to modify equipment and industrial processes to expand electric generation operations was difficult to justify.

The enactment of the Public Utility Regulatory Policies Act in 1978 (PURPA) removed many barriers to the growth of industrial cogeneration by freeing industrial cogenerators from utility-type regulation, assuring interconnection to the utility grid, requiring utilities to purchase cogenerated power at a fair price and assuring that utilities provide standby and maintenance power at reasonable cost. In enacting PURPA, Congress recognized the major benefits to society of the 1) greater energy efficiency of cogeneration, 2) increased reliability of the nation's electric generating system, 3) greater use of renewable fuels (such as wood residues, hydropower and municipal waste) to generate electricity, and 4) reducing the nation's dependence on imported oil.

These factors were particularly significant as the price of imported oil escalated in the 1970s. Concurrent with the rise in fuel prices, utilities were experiencing increased costs of environmental protection, high interest rates, construction delays, rapidly increasing equipment costs, financing difficulties and potential fuel shortages. All of these factors combined to cause: 1) a correspondingly sharp increase in utility rates; 2) some service curtailments in parts of the country; and 3) a reawakening of interest in the development of industrial generation of electric power.

The paper industry was very supportive of PURPA and the Federal Energy Regulatory Commission (FERC) regulations establishing the framework for states to implement the law. Unfortunately, litigation in state and federal courts rendered the future of PURPA uncertain and therefore delayed additional development of cogeneration and hydropower by industry.

Shortly after PURPA was enacted, a court in the State of Mississippi found PURPA unconstitutional, but the U.S. Supreme Court in 1982 reversed the Mississippi court's decision and upheld PURPA. API participated in the case as an amicus curiae, supporting PURPA as constitutional. In 1980, several utilities challenged in federal court the FERC regulations implementing the federal program. API joined FERC in defense of FERC's regulations all the way to the U.S. Supreme Court where they were upheld in May, 1983. This major victory for cogeneration development ended five years of uncertainty over whether the federal program encouraging cogeneration development would stand. These two cases were the beginning of efforts by the electric utility industry to prevent implementation of PURPA.

Despite the major hurdles at the federal level since PURPA's enactment in November, 1978 and other issues arising at the state level, the paper industry has added over 2100 megawatts to its cogeneration capacity. According to API data, the industry increased its electricity production using cogeneration by 26% between 1982 and 1985 and increased its electricity sales to utilities four-fold in this three-year period. API estimates that the industry in the next five years can increase its cogeneration output by 30%. This estimate assumes that PURPA will remain in effect as written and that there will be no major obstacles to its implementation at the state level.

What factors influence the expansion of cogeneration in the industry? PURPA has been and will continue to be instrumental in creating an environment where industry can succeed in making the additional investments necessary to cogenerate electricity. In the early 1980s, companies began to factor the economic incentives of expanding their cogeneration potential into their planning, capital budgets, process designs and plant construction. The opportunities to install cogeneration equipment typically occur as part of either a modernization of an existing mill or construction of a totally new facility. The various factors affecting the economics of cogeneration investments at a paper mill include buy back rates for cogenerated power, the opportunity to purchase and sell power simultaneously, projected cost savings to cogenerate instead of purchasing electricity from the local utility, the type of fuel used, and financing arrangements.

Keep in mind that not until May 1983 was the validity of the federal PURPA program, as established in the FERC regulations, affirmed by the U.S. Supreme Court. The uncertainties caused by the extended legal challenge to the rules postponed development and, in some cases, resulted in missed opportunities for cogeneration development by industry.

BENEFITS OF PURPA

How effective is PURPA? The paper industry believes PURPA already has brought about significant development of cogeneration and small power production by industry. This has occurred despite continued controversies at both the federal and state levels over how the law is being implemented. It should be clear that the comparatively small increments of electric generation capacity made possible through cogeneration relative to the size of new utility stations are beneficial at a time when many utilities are experiencing tremendous cost increases for new major electric generating facilities. Cogeneration better matches marginal growth in electricity demand than large baseload generating units, thereby deferring or cancelling the need for additional large and costly utility power plants. When a utility purchases cogenerated power, the capital investments and operating costs, including any project cost overruns, become the financial risk of the cogenerator, not the utility or its ratepayers. Therefore, ratepayers do not pay for overly expensive power or for the availability of power supplies not received. The ratepayer pays nothing extra by virtue of the fact that the local utility buys power in small increments. The utility often is relieved of the financial burdens of building new large units or firing old, inefficient and costly generating units; its cost of capital is reduced.

In the past, the avoided cost principle in PURPA has been subject to controversy and described as unfair to ratepayers. I would like to clarify the principle of full avoided cost and why ratepayers benefit under it.

In order for the nation to achieve PURPA's objective of maximizing cogeneration and small power production, the federal legislation authorized FERC to set the optimum economic price signal to encourage industry to realize its potential to make electricity. Full avoided cost is the cost incurred by the utility to generate, or buy from another source, the same unit of power that is purchased from the cogenerator. Therefore, the ratepayer pays no more for electricity purchased by the utility from a cogenerator than for electricity produced by the utility itself. Cogeneration by industry is encouraged to a maximum extent without increasing retail power rates. The paper industry long has supported the position that federal law should not require utilities to pay more than full avoided cost.

Even in areas of the country where there is a surplus of electricity, the addition of cogenerated electricity to the utility system will not adversely affect ratepayers. If the utility has excess capacity now and for the foreseeable future, the cogenerator will not receive an avoided capacity payment. Rather, the avoided cost payment will be based solely on the utility's avoided energy cost, which is primarily the cost of fuel that the utility can avoid purchasing for its plants if it buys cogenerated electricity instead.

In practice, most utilities sign electricity purchase contracts at a level below the utility's avoided cost for the life of the contract. Although there is no guarantee that the payment to a cogenerator will be lower than the utility's alternative costs in a single hour or a single day, over a longer term, the price paid to the cogenerator will redound to the benefit of ratepayers. These ratepayers will avoid the rate base effects of new, large, and expensive baseload capacity, and in many cases, will be paying for cogenerated electricity at a rate that is below even the utility's avoided energy cost alone.

There are additional benefits to the nation of cogenerated power by industry:

- Lead times for cogeneration are from one to three years as opposed to ten to fourteen years for large coal or nuclear utility plants.
- There are fewer emissions per kilowatt hour of electricity generated than in conventional utility generating facilities.
- Cogeneration reduces production costs for industry, making U.S. industry more competitive.
- Cogeneration encourages greater use of renewable fuels, such as biomass.

SPECIFIC ISSUES ON IMPLEMENTATION OF PURPA

The program envisioned by the authors of PURPA is only now beginning to be realized. Two examples of its impact are, first, the increasing amount of cogenerated power purchased by utilities in the last two years; and, second, the fact that in many states the avoided cost is coming down as more cogenerators come on-line and as the market price of oil and gas decreases. Reduced avoided costs certainly have occurred in the State of Idaho, where my company was founded and still has significant operations.

Now that the status of the federal law is more certain, we find that disparities are developing on the state level as different states develop regulations and enact "mini-PURPA" laws. We recognize states' rights and their obligations to draft legislation and issue rulings tailored to their particular needs. But we are disappointed that some utilities seem to be fighting the battle of PURPA over again in different state capitals and that some state commissions do not understand the alternative avoided cost methods for pricing cogenerated electricity that will benefit ratepayers over the short- and long-term.

The following is a summary of specific issues that are frequently misunderstood or improperly addressed by state utility commissions or of areas in which FERC could provide regulatory guidance so that PURPA will work as efficiently as possible.

Sanctity of Contracts

As a general matter, a cogenerator needs a long-term contract for the sale of electricity to a utility in order to secure financing for the facility. Moreover, a cogenerator needs the assurance that the contract entered into with a utility for sale of cogenerated power will not be subject to revision at a future date. The economic analysis justifying the worthiness of a cogeneration project mandates this. A utility's projection of its avoided costs has at least as good a chance of being too low as too high, and should not be subject to 20-20 hindsight if conditions change years later.

Unfortunately, at least one state has regulations allowing its state commission to reopen at a later date contracts entered into voluntarily by a cogenerator and utility, which were initially approved by that commission. This procedure threatens the sanctity of contracts, making financing of cogeneration projects virtually impossible. Despite a request to do so, FERC has chosen not to issue a policy statement clarifying this type of procedure as a violation of PURPA and the FERC regulations. This situation is very unfortunate.

Utility Reimbursement for Payments to Cogenerators

Since a utility, when purchasing power at avoided cost under PURPA, is acting in a prudent manner as the agent for its ratepayers, then it follows that its ratepayers should reimburse the utility for the cost of that power. The state commission has the authority to review the contract between the utility and the cogenerator to make sure that it is consistent with avoided cost principles. Once the state commission has approved the contract rates, the commission must be required to allow the utility to recoup the payments made to cogenerators under approved contracts. The state commission, in applying federal law, in effect has determined that the cogeneration purchases were made prudently. In API's view, thse payments are guaranteed under federal law.

In recent months, a few state commissions have indicated a reluctance to give the utility the assurance of a full reimbursement of payments made to cogenerators. As a result, utilities in those states have been similarly reluctant to enter into agreements with cogenerators, or have insisted on a clause that permits the utility to stop paying the cogenerator if the state commission denies reimbursement, which is fatal to the financing of cogeneration projects. API suggests that either FERC or Congress take appropriate measures to ensure that utilities can be reimbursed for payments to cogenerators.

Levelized Payments

The federal rules permit, but do not require, state commissions to direct utilities to enter into levelized payment arrangements for the purchase of cogenerated electricity. Levelized payments are payments that are at a fixed level for the life of a long-term contract. The level selected is at or below the utility's avoided cost for the life of the contract, although it may be somewhat higher than the expected avoided cost in the early years and somewhat lower than the expected avoided cost during the later years.

Levelized payments are frequently needed by cogenerators to enable them to pay off their financing costs for the capital expenditures of the facility in the early years. In exchange for the utility's agreement to provide levelized payments, cogenerators routinely accept payments that are below avoided cost for the term of the agreement. In addition, levelized payments for avoided capacity that are timed to coincide with the date that the utility would otherwise have needed capacity will produce payments that are lower than the avoided capacity costs of the utility, since the utility-owned new capacity would be "front-end" loaded under traditional ratemaking principles.

Simultaneous Purchase And Sale

The federal rules allow an industrial cogenerator the option of selling all of its cogenerated output to the utility and buying back from the utility all of the electricity it needs for its industrial operations, rather than simply selling to the utility only the excess of cogenerated electricity above the level needed for the industrial's own load. This alternative approach is known as the "simultaneous purchase and sale" rule, and it has been widely misinterpreted as a rule that adversely affects ratepayers. In fact, the rule helps ratepayers.

Under the simultaneous purchase and sale rule, the utility buys cogenerated power at its avoided cost, and keeps the industrial load as a full electricity customer of the utility, thus maintaining its customer base and keeping the rates for its other customers at the same level. If, on the other hand, the industrial cogenerator sold only the excess electricity to the utility, the utility would lose the industrial load, thus forcing the utility's remaining customers to pay for the fixed utility costs that the industrial would otherwise have paid. In other words, the rates of the remaining ratepayers would go up. Additionally, the cogenerator can develop power at cost effective prices for the ratepayer, even if the average price of power will not support cogeneration to serve its own load.

Far from being a windfall to cogenerators, the simultaneous purchase and sale rule is actually a ratepayer protection measure which should be encouraged by state commissions.

Back Up Power

Currently before the Federal Energy Regulatory Commission for review is its August 1985 ruling in the Alcon Pharmaceutical case. According to this decision, third-party financed and owned cogeneration can be denied standby and backup power by the local utility if the user of the cogenerated steam and electricity is a separate corporate entity. It is troublesome that FERC chose to let the way a cogeneration project is financed become a barrier to proper implementation of PURPA, especially when PURPA clearly sought to assure cogenerators back-up power. Back-up power is needed when a cogeneration facility is temporarily shut down for maintenance and repairs. There can be no industrial cogeneration without back-up power in these circumstances. FERC has agreed to rehear the case. Nonetheless, the decision has already been cited in various states by utility commissions and is discouraging industrial cogeneration development. The paper industry looks forward to a reversal of FERC's policy on this matter.

Utility Ownership

PURPA and its regulations wisely limit public utility ownership of qualifying projects to 50%. One of the purposes of the Congressional limitation on utility ownership was to diversify the sources of utility generation. In other words, Congress hoped to spur competition in the utility field while simultaneously promoting fuel efficient and renewable resource facilities. Congress was well aware that electric utilities had ample opportunity to invest in cogeneration and in renewable resource facilities over the years and did not avail themselves of that opportunity. Congress believed that it was time to encourage new entrants into the marketplace that would be free of the regulatory restraints and guarantees to which utilities were subject and that would be allowed to sell their product to utilities that had historically refused to deal with them.

Nothing in PURPA prevents a utility from engaging in cogeneration or small power production - up to a full 100% ownership position. The present ownership limitation merely reflects the reasonable conclusion that utilities need not be accorded the special incentives (i.e. avoided cost, little regulation, assured interconnection) that are needed to get non-utilities to develop electric generation. The technological advantages of cogeneration are fully available to utilities today and are being used by them. In fact, some utilities have already built or are negotiating to build cogeneration facilities in conjunction with industrial companies. Moreover, as regulated entities, utilities are guaranteed an opportunity to earn a fair return on their investment. There has been no showing that they require the incentives provided by PURPA.

Making PURPA applicable to utilities to any greater extent than it is now will encourage utilities to engage in even more foot-dragging and delay. Cogenerator negotiations with utilities could be stalled with the utility seeking to hold out for ownership of facilities rather than proceeding with the purchasing of power from the cogenerator. Moreover, utilities would be encouraged to shift productive assets into, or to acquire qualifying assets in, unregulated divisions or subsidiaries that would be operated for the benefit of stockholders rather than to produce balanced benefits to ratepayers and stockholders, which is commonly required by state utility regulation.

Loosening the 50% restriction on utility ownership could lead to a form of "cream skimming" that would be highly detrimental to industrial cogeneration efforts. Utilities could build unregulated cogeneration facilities and receive the higher avoided cost payments for themselves through their control of the contract negotiation process. There would be substantial danger that the enticement of unregulated profits from deregulated utility generation will encourage utilities to neglect the development of lower net cost baseload generation capacity.

Access to Transmission Systems

Companies in the paper industry would welcome the opportunity to have equal access to the electricity transmission network in the United States as it would allow them to compete for sales and purchases more broadly when considering the construction and operation of qualifying facilities. This opportunity would, of course, encourage greater development of energy efficient cogeneration and the use of renewable resources to generate electricity, contributing to lower energy costs for a broader spectrum of ratepayers.

Unless a local utility agrees to deliver the power to others through use of its transmission system, qualifying facilities will have no other market. If potential qualifying facilities are limited to a single market for their product (i.e., the local utility), in many cases such facilities will simply will not be constructed.

We in the paper industry know that the issue of "wheeling" has been the subject of some heated debates during consideration of legislation on the relicensing of hydroelectric facilities. During testimony on the bill before this committee, our industry stated that, although we favor wheeling as a concept, we felt it had no place in the more narrowly drafted hydroelectric bill which we supported. The industry supports wheeling as a means of supplying lower cost power to utilities other than the local utility, thus providing a greater benefit to ratepayers.

For example, a potential qualifying facility may find that the local utility has excess capacity and therefore only can pay avoided energy costs if it buys the cogenerated output from a qualifying facility. However, if the utility next door needs generating capacity as well as energy, the potential qualifying facility would prefer to sell to that utility, but can do so only if the local utility will wheel the facility's power to the utility next door. Such an arrangement may well lower rates for ratepayers served by the second utility.

However, under the current FERC regulations the local utility in this situation can frustrate any cogeneration project simply by offering to buy the output of cogeneration, thus blocking the use of its transmission system for the sale of cogeneration to the next utility that can pay more for the power. In effect, FERC is unable to order wheeling of any kind under present law. The paper industry maintains that, on a case by case basis, there should be the opportunity to obtain a wheeling order from FERC if the buyer and seller agree.

In concluding my comments on transmission access, let me state what this industry has stated since the enactment of PURPA. The paper industry is willing to pay for reasonable connection, interconnection, and other associated costs to ensure adequate system reliability. The question of system reliability, often raised by utilities, is as important to us as it is to them.

CONCLUSION

In the past, some utilities have claimed that inflated oil and gas prices and tax breaks have unfairly benefitted the cogeneration industry and that otherwise uneconomic generating capacity has been contructed. Whatever the merits of these claims in the past, they have no validity today. Falling oil and gas prices have led to a precipitous decline in utilities' avoided energy costs and have discouraged many projects that would have been viable only a few months ago. In addition, the proposed elimination or reduction of tax benefits for capital investment, contained in the Senate and House tax bills, will also reduce the number of viable cogeneration projects in the future.

In short, cogenerators, like all other industrial enterprises, will be operating in a new economic environment in which the marketplace will determine the appropriate amount of cogeneration development, as long as the states, in implementing PURPA, allow the cogeneration program to operate as Congress intended. States and FERC must be encouraged to take an active role in promoting cogeneration development in order for the promise of competition in the electric utility industry to be more fully realized.

For the reasons stated above, the paper industry believes that PURPA, as written, best serves the intent of expanding cogeneration in the industrial sector. Implementation of this Act to date has shown that lower rates will accrue to the ratepayer. Complete implementation will make that even more evident.

SUPPLEMENTAL STATEMENT OF THE AMERICAN PAPER INSTITUTE FOR THE RECORD OF THE SENATE ENERGY AND NATURAL RESOURCES COMMITTEE OVERSIGHT HEARINGS ON IMPLEMENTATION OF PURPA

The American Paper Institute appreciates the opportunity to respond to a number of issues raised at the June 3 and 5 oversight hearings of the Senate Committee on Energy and Natural Resources on implementation of the Public Utility Regulatory Polcies Act (PURPA).

1. The Need for Power

Several utilities objected to being compelled to buy power when they didn't "need" it. Senator Johnston's second question to API presents the issue in terms of unneeded capacity only, which, of course, is the proper formulation. It seems likely, however, that some of the utility spokesmen were disturbed about having to buy energy from qualifying facilities when they had the capability to generate adequate amounts of energy themselves.

There is a technical situation, known as "light-loading," in which utilities cannot readily accommodate qualifing facility ("QF") energy, and when, in fact, avoided cost can be negative; i.e., in certain unusual circumstances, for a few hours at a time, requiring utilities to accept QF energy can actually impose costs on utilities. The FERC rules deal adequately with this situation, by providing that utilities do not have to buy electricity during these periods. At all other times, however, utilities can avoid burning fuel or spilling water stored to generate electricity if QFs provide the electricity instead. The avoided cost may be low, but there is, nonetheless, an avoided cost.

In enacting PURPA in 1978, Congress expressed its preference, all other things being equal to the ratepayer, for electricity generated by QFs rather than by conventional utility plants; this goal is met at no additional cost to the ratepayer when conventional central station generation is backed down to accept QF energy at a price equal to the utility's avoided cost. Thus, in API's view, utilities who discuss their "need" for energy, rather than capacity, are misstating or misunderstanding the issue.

2. Cogenerator Sizing Decisions

A related issue is the utilities' attack on what they regard as oversized cogeneration facilities. As I discussed in my response to Senator Johnston's first question, cogeneration facilities that meet QF qualification requirements are more efficient than non-cogenerating utility plants. It is not surprising that some utilities would like to return to the day when industrial plants with cogeneration capability generated only enough electricity to serve their internal needs, and did not compete with utilities to supply power. Many utilities refer to such installations as "classic" cogenerators. The "classic" cogenerator came about, however, because of the very barriers that PURPA meant to strike down: unacceptable federal and state utility-type regulation and the unwillingless of utilities to buy electricity at all, or to offer to buy it at a fair price.

While it is true that the changing conditions of the electric utility industry in the late 1960's and early 1970's meant that cogeneration was often becoming economic where it had not been for many years, today cogeneration is cost-competitive with most utility generation. Thus, lowering institutional barriers to competition with utility generation greatly enhances economic efficiency in generation of electricity.

Indeed, in many regions where utilities do not need additional capacity, cogenerators have been able to cover the entire capital cost of their facilities simply by the difference between their operating efficiency and that of the utility. So long as cogenerators are more efficient than the utilities to which they sell energy - as they must be in order to comply with the FERC regulations - there is no need for concern over cogenerator sizing decisions. Rather, there is every reason for permitting cogenerators to take advantage of the economies of scale, and thus to promote economic efficiency even further. It should be noted that in most states where cogenerators receive capacity payments, the value of the capacity is based on avoided utility capacity construction, which usually reflects enormous economies of scale. Exploitation of economies of scale has been the main justification for building plants larger than are needed immediately to meet utility loads.

3. The Level Playing Field

There has been much discussion of the idea that utilities have been disadvantaged by not "playing on a level field" with QFs. The phrase is used to describe a number of distinct and unjustified utility complaints about PURPA.

a. On the most fundamental matters, the playing field is still steeply tilted against QFs. After all, utilities remain monopolistic sellers of electricity in all retail and most wholesale markets (excluding QF sales to utilities), and monopsonistic buyers of electricity. Unless a state commission aggressively establishes ground rules implementing PURPA, through devices such as standard price offers and contracts designed to permit financing of QFs, utilities can prolong contract negotiations almost indefinitely, exhausting the resources and destroying the interest of project developers. Of course, the enormous resources that utilities bring to bear in these cases to discourage QF development is underwritten by ratepayers. In fact, except where utilities have decided that the risk of building new plants is so substantial that they would rather have others undertake the risk, utilities have nothing to gain from purchasing electricity from a QF in which they have no investment. Since all utilities subject to rate of return regulation earn a profit on their investment only, and not their expenses, the effect of QF development is to reduce aggregate utility investment, and thus profits.

The answer, in our view, is for state commissions to begin rewarding utilities that are prudent purchasers of electricity - whether from another utility or a QF - and penalizing utilities that are not. Purchasing energy at its lowest price is by no means the only standard for judging a utility's performance in this area. Indeed, utilities that bargain so hard for low rates with QFs that little if any QF capacity is developed in their service territories, have also failed in their responsibility to ratepayers.

b. It is true that in the past certain tax provisions have favored QFs. However, it is certainly clear that these provisions are soon to become a thing of the past.

c. It is also true that cogenerators burning oil and gas can readily obtain exemptions from the Powerplant and Industrial Fuel Use Act, whereas utilities cannot build new gas- or oil-fired facilities that operate for more than

1,500 hours a year, unless they comply with much more stringent exemption provisions. Although, as discussed in Mr. Nicholson's answers to Senator Johnston, we do not believe that oil and gas fired cogenerators can displace solid fuel-fired utility facilities over the long run, API believes that the Fuel Use Act should be repealed.

4. The Simultaneous Purchase and Sale Rule

Some utility representatives apparently view the Simultaneous Purchase and Sale Rule as one of the more egregious examples of a tilted playing field. It is apparent, however, that no provision of PURPA's rules is more widely misunderstood than this one. For example, one utility representative testifying at the hearings complained repeatedly about having to buy electricity at, say eight cents per kWh and having to sell it at four cents. This example is perfectly plausible. But, contrary to the utility spokesman's expressed concerns, it will not lead to either overcharging the ratepayer or bankruptcy of the utility.

The difference between the two figures is that the four cent rate at which the utility sells electricity to its retail customer is an average cost figure. An average figure is made up of both higher and lower figures. The price that the cogenerator is paid, on the other hand, is based on the utility's highest cost generating unit, in terms of both fuel and other operating and capital costs.

This is appropriate, because if an industrial customer of a utility paying average cost rates were to begin to generate its own electricity, the utility would not save or avoid its average cost. Rather, the prudent utility would turn off its most costly generating unit when its load was reduced. Thus, in the example given by the utility's spokesman, the utility's highest cost unit produced electricity at eight cents per kWh, and that is the rate at which the utility would save if its customer load were reduced because the industrial facility dropped off the system. If, instead, the industrial facility stayed on the system, but sold its output to the utility at eight cents per kWh, making it unnecessary for the utility to generate electricity at the same cost, the rates to the other customers would be unchanged: the average cost of generation of electricity to the utility would still be four cents per kWh.

Another, more likely example is where the industrial concern can build and operate a generating facility for seven cents per kWh, and the utility, faced with building a new unit unless it finds an alternative supply, will have to spend eight cents or more per kWh to build and operate a new facility. Since the utility has a large existing base of older, depreciated plant, this will only increase its average cost by a little, say to 4.5 cents. If the industrial concern were required to consume its own output to meet its own load, and were allowed to sell only its surplus at eight cents per kWh, it would be unlikely to build a facility at all: it would have to sell electricity to itself at seven cents per kWh for all its plant usage, and thus forego the opportunity to buy from the utility at four to 4.5 cents. Even if the utility were building twelve or fifteen cent per kWh plants, its average cost, because of its large capacity base, is unlikely to go up to more than, say five or six cents. In this situation, were it not for the Simultaneous Purchase and Sale Rule, the cogenerator would have to forego four to five cent power from the utility for its own electric use, and instead purchase from itself at seven cents. In this situation, someone loses: the industrial concern. If, on the other hand, the industrial concern old all of its output to the utility at eight cents per kWh (the utility's avoided cost), other ratepayers would pay the same or less for power than they would have had the utility built its unit. Society at large would also benefit if the more efficient producer, the industrial facility, builds the new plant rather than the utility, which is the less efficient producer.

Perhaps a more common circumstance these days is where a utility brings into service a very expensive new plant which drives retail rates up sharply. In this situation, the industrial concern is likely to build and operate a cogeneration facility in large part to reduce its purchases from the utility. Since the utility's costs are in significant part fixed, and its retail sales go down when the industrial concern leaves the system or reduces its purchases, those fixed costs must be spread over reduced electric sales, thus increasing the burden on the utility's captive (non-self-generating) customers. We are familiar with a few cases in which the Simultaneous Purchase and Sale Rule has preserved a utility's existing sales base, despite sharply increased retail rates, because a cogeneration developer sold all its output to the utility at the utility's avoided cost, and its associated industrial concern continued to take all of its electric needs from the utility, thus sparing the utility's captive customers the burden a paying for more of the utility's fixed costs.

The FERC believed, and we still agree, that in the long run greater efficiencies are likely to be achieved if one treats distinctly the electricity production of cogenerators and the electricity needs of their associated industrial facilities.[1]

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[1] From a microeconomic point of view, the simultaneous purchase-sale rule is good policy because it promotes economic efficiency. Buy-back rates set at full avoided cost provide the most efficient pricing signal to QF generation of electricity: the rule provides the proper incentive for construction of QFs with costs less than

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There are, apparently, one or two horror stories in circulation about abuses of the Simultaneous Purchase and Sale Rule. One involves using utility power to pump water up a hill to an elevated reservoir, then letting the water run down the hill through turbines to generate electricity and sell it as QF output. We are not familiar with the details of this case, if it exists, but it raises a number of interesting points. First, as we understand the FERC rules, the Simultaneous Purchase and Sale Provision pertains to

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the utility's full avoided cost. A buy-back rate set at less than a utility's full avoided cost would encourage less than an optimal level of QF production, because some QFs with costs less than utility avoided costs would not be able to operate profitably. Disallowing QFs to sell all of their output to utilities at utilities' full avoided cost (while purchasing all of their needs at average utility costs), deprives QF developers of the proper price signal for development and generation.

Thus, setting buy-back rates for all QF output at full avoided cost encourages reliance on least-cost sources of electricity, *i.e.*, it enhances "productive efficiency." The real beauty of the full avoided cost rule is that it it effects a "Pareto improvement" *i.e.*, it enhances productive efficiency without making the utility or its ratepayers any worse off: the utility pays QFs only the costs it would have incurred if it had generated the electricity itself, and the ratepayers pay no more for that electricity; indeed, ratepayers often pay less because the rule keeps industrial facilities associated with cogenerators on the utility's load (thus sharing payment of fixed costs), and, moreover, QFs often agree to be paid a buy-back rate equal to less than full avoided cost, in return for concessions on other aspects of their relationship with the utility that are not reqired by PURPA.

purchases by an electricity user that is associated with the cogenerator or small power producer, but it does not apply to electricity purchased for the sole purpose of generating electricity. (In fact, the Conference Committee Report to PURPA does classify electric energy storage facilities as qualifying small power production facilities, but we do not find any provisions in the FERC rules on this point.) Even if this described facility were to qualify under the FERC rules - and it appears to us that it would not - the company in question would under most circumstances lose a great deal of money due to the inefficiencies of both pumping operations and hydroelectric generation.

5. Wheeling

As avoided cost rates have dropped due to more QF power coming on line, declining oil and gas prices, and adjusted load growth projections, it has become increasingly common for a QF to find it more attractive to sell power to a remote utility that is a willing buyer rather than the utility in whose service territory the QF is located. However, if the local utility has a low avoided cost and an adjacent utility, or a company three utility systems away, can provide a better market for the QF's output, the QF must attempt to negotiate one or more wheeling agreements with the intervening utilities.

The FERC's rules provide that if the local utility offers to buy QF output at its avoided cost, it does not have to wheel the QF's electricity. Many utilities stand on their rights, or, more precisely, on their lack of obligation to wheel under the FERC rules. This is most likely where the local utility also hopes to sell electricity to the remote utility, though perhaps at a higher price than the QF is demanding. This ability of a utility to keep a QF from getting its output to the highest price (and cost) market clearly produces inefficiencies, yet there is no viable remedy under federal law to compel wheeling outside of an antitrust action; and it is simply not feasible for project developers to undertake a full-blown antitrust suit before beginning the usually difficult process of negotiating a contract with a remote facility and financing and building a QF. Indeed, in most cases, the threat of an antitrust suit against the local utility will be enough to make the remote, would-be buyer terminate discussions about the possible purchase.

In other instances, the local utility will agree to wheel only if the remote utility asks it to, and the remote utility will willingly purchase, but will not request the local utility to wheel. This Alphonse and Gaston act is almost always enough to kill the project. As utility-to-utility transactions increase, and the market for bulk power opens up, discrimination in providing transmission services to QFs becomes more and more glaring. API therefore believes that wheeling is a critical area for legislative reform.

6. Long-Term Cogenerator Dependability

Both state utility commissions and utilities are becoming more sophisticated in drafting utility purchase agreements with QFs so that under reasonably foreseeable circumstances, there will be a continuing incentive for the QFs to produce power. For project-financed facilities, the banks have been the most rigorous policeman of this kind of contractual arrangement, at least for the financing term. A number of factors enter into whether there need be any serious concern over this issue: the dependability of the technology, the operating cost of the QF (which, in the case of cogenerators, depends primarily on fuel choice), and the price escalation provisions in the power sales contract, if any. Obviously, the type of contract that most seriously raises this concern is a so-called front-end-loaded contract, where the QF is paid more than its value in the early years of its contract, and less in later years. (Of course, when compared to the revenue requirement effect of a new utility plant, the cost of which is recovered overwhelmingly in the early years of service, QF contracts are only minimally front-end loaded.) However, again, there exists an almost self-correcting mechanism here: the kind of plant that needs the most front-end loading is characterized by high capital and low running costs. Thus, where the contract for sale to the utility extends beyond the term of the financing, there is little reason for concern about whether a QF will continue to operate. Again, this is an area in which the states can best address the problem, if there is any problem, by reviewing contracts to ensure that they are structured so that it will always be in the QF's best interest to continue to produce electricity throughout the life of the facility.

7. Dispatchability

There has been increasing discussion recently about dispatchability, i.e., the ability (or willingness) of the QF to increase or decrease electrical output at the utility's direction. It is apparent that some technologies have the capability for at least some dispatchability, whereas others (such as run-of-river hydro and wind energy facilities) do not. Both equipment capability and steam production requirements can affect QF dispatchability. It is noteworthy that in many states, if not most, the measurement of avoided cost has assumed little if any dispatchability; thus, the ratepayer gets a bargain by the utility's purchase of QF power if the contract provides for some dispatchability.

Since the FERC rules do not require utilities to purchase from QFs during light-loading periods, when dispatchability is essential, the utilities do have power on the dispatchability issue. Because the capability to accept some degree of dispatch varies so much from facility to facility, this is a matter not only best left to the states, but best left to negotiations between QFs and utilities, so long as those negotiations proceed in good faith. Interestingly, this is an important issue only in states in which PURPA has been such a success that it is anticipated that QFs will constitute a significant portion of the state energy mix in future years.

8. State Commission Price Redetermination Provisions

A number of states have been sorely tempted to require provisions authorizing them to alter essential contract terms, especially price, upon a finding of changed circumstances. API believes this to be illegal, improper, and unnecessary. Anticipating the need of QF developers for some price predictability, if not certainty, so they could make substantial investments in QF facilities or attract loans enabling developers to build facilities, the FERC provided in its rules that a QF entering a long term contract can elect at the time of the commitment to lock-in current estimates of avoided cost. Since one of the fundamental purposes of PURPA was to remove the obstacle of regulatory risk for QFs (which, as the Conference Committee pointed out, do not have any constitutional guarantee to a compensatory return on investment), the reservation of authority by state commissions to alter essential contract terms is entirely inappropriate. For obvious reasons, appreciated by both the Congress in 1978 and the FERC in its rulemaking, reservation of such authority makes financing of most QFs difficult or even impossible.

Moreover, such a provision is fundamentally inequitable: once a utility's investment in plant is included in its rate base, it almost never will have its return altered, other than to track changes in the cost of capital. This disparity in treatment between QFs and utilities becomes particularly glaring when one realizes that almost all QFs are paid on a kWh produced basis, whereas utility plants in rate base can be idle for sustained periods without being removed from rate base, so long as there has been no imprudence or negligence on the part of the operator.

Finally, such a provision is unnecessary in most instances because most power sales agreements contain variable as well as fixed price components; and the energy payments usually fluctuate with the cost of utility generation or of a particular fuel. Since the energy, or variable, rate will reflect changes in market conditions, there is no need for a further reservation by state commissions of authority to abrogate or amend the contract.

9. Standby Rates

Another important area in which there is increasing activity at both the federal and state levels is standby rates. Traditionally, most utilities had standby rates that discouraged self-generation by utility customers. The Congress recognized that a fair rate for services a QF needs from a utility was an essential component of the PURPA program. The FERC rules also reflect an understanding of this requirement, but require no more of the states than that they price services to QFs in a manner consistent with their pricing of service to others.

As utility avoided costs have fallen, more and more QFs have found it uneconomic to sell to utilities and more economic to use the power themselves. Under these circumstances, the backup or standby rate becomes vital to the economics of cogeneration and, indeed, vital to the operation of the industrial plants that so often are the host for such facilities. The FERC's unwillingness to enforce certain essential provisions of its rules in recent years may be taken as a signal by certain utilities, and perhaps by some states, that they are once again free to employ the device of instituting unreasonable standby rates for QFs to discourage cogeneration and small power production.

Conclusion

In large portions of the country, PURPA is a program whose time has not yet arrived. In other parts of the country, PURPA has already been a notable success, despite the short period of time since serious legal challenges to the program were defeated. In those areas, PURPA has delivered the benefits of energy efficiency, diversity of supply, enhanced power planning, reduced adverse environmental impacts, and reduced dependence on foreign sources of energy.

Utilities have shown that effective development of this revised industry can be forestalled by sustained litigation and general recalcitrance. Any change in the essential provisions of the statute or FERC's regulations will undoubtedly lead to another round of litigation and another sustained period of uncertainty about the program. API strongly believes that no fine tuning, by either the Congress or the FERC, is worth the sustained paralysis of the program that would follow a change in the statute or rules.

Thank you for this further opportunity to present API's views.

The CHAIRMAN. Mr. Brown.

STATEMENT OF REUBEN BROWN, ON BEHALF OF THE NATIONAL HYDROPOWER ASSOCIATION

Mr. BROWN. My name is Reuben Brown, from the Woodside Group, Inc., located in Stamford, CT. I have been involved in hydro development activities since 1976, when the Allis Chalmers Corp. employed by services to conduct a market inventory of small scale hydroelectric sites in the Northeast, and I have been involved in PURPA implementation issue since 1978, as a consultant, and indeed, a developer of two small hydro sites in North Carolina and Maine.

I am here representing the National Hydropower Association. We represent a diverse group of persons in the hydro industry and, in effect, are the hydropower trade association at the present time.

PURPA's enactment was a major force in creating the independent power industry. Paraphrasing the last speaker, it was a major force in creating a competitive power industry in the United States.

To add one supplemental comment to the competitiveness issue, last week I was reviewing testimony, or comment filed by a utility in a Western State that was specifically pleading with its commission to maintain regulation and not permit competition from PURPA-related activities.

This is a utility which in that State, to date, only buys the output of three small windmills. They are truly being dealt a competitive heart blow.

PURPA can be credited in many ways with breaking this monolithic hold on electric generation, and I think we heard a variety of examples of how it is hurting some of the utilities in some specific parts of the country to respond to it under the frameworks that their particular commissions have identified for them.

Speaking from experience in a variety of parts of the country, I have worked in 14 different States on projects and negotiated contracts for PURPA regulations and rules in those settings. I think this is an atypical experience that you have heard today from utilities. I think it represents an experience that in other places is very different, reflecting particularly in States, in situations where capacity has been needed, a broader vision by the utility management themselves and by the regulators.

The continued development of the Nation's small scale hydropower industry, for example, is viewed in many places a beneficial act that has been encouraged by utilities themselves. A variety of utilities have historically operated small scale hydroplants and in the period of 1976 to 1980, while I was a consultant for the State of New York Small Hydro Task Force, several of those utilities were reviewing plans themselves for the development of over 300 megawatts of small scale hydroelectric plants.

One of those utilities has specifically created a subsidiary in the wake of legislation to implement PURPA that was developed in New York in 1980, which is developing some of those small scale hydroplants. The utility has developed some of them, and others have been put into the open market place for purchase from the utility to develop those sites.

I checked last week with the office of environmental conservation in New York as to how many projects have been processed since 1978. As of August 1, 1985, 58 projects have been licensed or exempted that are small scale hydro projects. By the present time, another 20 to 25 contracts have been—other licenses or permitting circumstances have occurred.

The Department of Environmental Conservation of New York Regulatory Affairs Unit reported to me that by the end of 1986, they expect between 90 and 100 projects to be licensed or exempted, representing an average of 3 to 5 megawatts apiece. So, we are talking of a capacity, since the enactment of PURPA, since the mid-1970's, that ultimately will probably be on line at the level of 300 to 500 megawatts, mostly small hydropower.

I think the point I would like to state very simply about hydropower, to correct a misimpression that may have been conveyed earlier by a speaking quoting the daily data, hydropower as we have seen it in this program is basically run of the river. So plant factors do go up and down as water flows, as it rains, as the weather changes.

That is anticipated in the contracts and guidelines that State commissions have laid down. It shouldn't be treated as the surprise it was stated to be here earlier today.

Hydroplants are different than cogeneration plants and they function over very long life cycles. The turbine industry that has refreshed itself and has come into being because of PURPA is still putting units into place that have extremely long lifetimes, compared to central generating facilities that are thermal in nature.

The point I would like to move to at this point is the issue that State commissions have been working effectively, albeit in very different ways. PURPA gave them the latitude to implement and they have chosen many different circumstances to meet their own needs.

In almost all of these circumstances, the utilities have been major participants in all negotiations. They have had nothing rammed down their throats that they weren't present to participate in. The fair-hearing process has worked in almost all States that I have been experienced with.

I want to speak to one minor issue that has not had excessive regulation by each of the State commissions, and that is the issue of the safety and interconnection standards, demonstrated earlier in the day, because in almost all of those instances and in almost all commissions the standards put forward on interconnection have been provided by the utilities. They have participated in their setting. The commissions have engineers of their own review them, and frequently, the argument by the small power producer is, please make those standards something generally agreed upon so that we don't have to negotiate them in every project instance.

I might thrown an anecdotal piece of information, not from a hydro facility but from a small scale cogeneration facility I reviewed in the service area of one of the utilities speaking. The day after an accidental fire occurred to an electrical installer, as he was putting wiring in, the wiring problem he was encountering in the panel had to do with the bypass that was effectively illegally put in place 40 years before by the utility's installers of that date and age, and did not involve safety devices and factors that would be in place today under the kinds of standards that are generally employed on these projects.

I want to go very immediately to the ratepayers' benefit issues, as I have outlined in my written statement, based on the decision in its cogeneration generic decision, that is the small power production and cogeneration decision in the State of Connecticut, as to benefits to the ratepayer. I simply outline them. We have heard them mentioned slightly before.

No capital cost overruns paid by ratepayers. No abandonment costs paid by ratepayers. This is particularly relevant in regions of the country where nuclear plants that are being terminated are sources of major concern. I will iterate a point on that. My firm was retained by the public advocate in the State of New Jersey in the wake of the Three Mile Island nuclear incident, and has worked with the State throughout that period on behalf of the ratepayers.

We were able to bring into being in the case of General Public Utilities a decision and an agreement to support a cogeneration program to bring these resources to their Jersey Central Power and Light subsidiary. Further, that subsidiary then created its own subsidiary, for which I planned the market, and evaluated a market to create a program to develop projects in this field.

I might point out that the U.S. Supreme Court, last Tuesday, turned down the final appeal of General Public Utilities for the ability to pass Three Mile Island costs onto the ratepayers. The stockholders had to absorb it, but in the face of that, the utility has embraced the cogeneration small power alternative and they are realizing a way of coping with abandonment costs; avoid the commitment in the first place.

Shorter construction leadtimes are another advantage to ratepayers. I will try to speed up my comments. Reduce the performance risks, reduce capacity reserve requirements, and there are a variety of miscellaneous economic benefits that help people stay in States.

I am not going to make general comments on avoided costs. I concur with most of the comments made by other speakers on this panel on that.

In my experience in a variety of negotiations and ratesetting procedures, the State commissions are generally farsighted. Long-term time frameworks are essential for small hydro projects, for example, because of the capital intensive nature of them, and that has generally been recognized in the rate treatment.

The reliability issues, I want to speak to an issue that is important to small hydro projects, perhaps not so to some other projects. The reliability and benefits of the small hydro facility out on the end of the distribution system is widely recognized by utilities and commission and credits are provided that are a cash benefit to the project for being there and providing output when it is provided.

The most amazing thing that I encountered in negotiating a contract in Maine, when I thought I was negotiating on a base rate, was when I received the draft contract from the utility, to find that

I had an additional 4-percent credit there for being there and preventing distribution line losses.

I hadn't even planned on it, but it was very useful for me to then make some of the capital cost adjustments that they needed to comply with their interconnection standards for the transmission equipment.

In conclusion, I would like to underscore the comments made by various people. PURPA is working. It is working differently in different places. It is working effectively in different places, and, by damn, it is creating competition in different places.

The most serious recent attack I have seen on PURPA in the form of a study by someone, goes through 300 pages of difficulties with PURPA and concludes, in the last final recommendation for the future that what we need is open competition; all plants being treated equally.

Thank you. I am sorry I took so long.

[The prepared statement by Mr. Brown follows:]

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Testimony of the

NATIONAL HYDROPOWER ASSOCIATION

Before the

SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

Regarding

PURPA IMPLEMENTATION

June 3, 1986

Mr. Chairman and Members of the Committee:

My name is Ruben Brown from The Woodside Group, Inc., located in Stamford, Connecticut. I have been involved in hydro development activities and PURPA implementation issues since 1978.

The National Hydropower Association ("NHA") appreciates the opportunity to testify before the Committee regarding the small-scale hydroelectric industry's experience with the implementation of the Public Utilities Regulatory Policies Act of 1978 ("PURPA").

The National Hydropower Association is the national trade association of the hydropower industry. It represents over six hundred industry members, including municipalities, private hydropower developers, equipment manufactures, engineers, contractors, financial community representatives and other professionals involved in the development and operation of hydropower projects, as well as hydro or independent power producers associations from the Northeast, Pacific Northwest and California and Virginia.

PURPA's enactment made the independent power producer industry. This industry has responded to this opportunity by increasing competition in the energy field which will, in the long run, benefit the nation as a whole, and increase the capacity and reliability of the nation's energy supply. NHA supports the Administration's move to deregulation, which has been enhanced by the policies implemented under PURPA.

DEVELOPMENT OF THE SMALL-SCALE HYDRO INDUSTRY

PURPA can be credited with breaking the monopolistic hold on electrical generation previously held by regulated utilities, and with opening the electrical generation market to competition by creating a sector of independent power producers. PURPA came into being as part of Congress's response to the energy crises of the 1970's. Prior to the energy crisis, energy supplies typically were thought of as unlimited in the United States, particularly with regard to electricity. In responding to the energy crisis, with the National Energy Act of 1978, in part Congress chose to expand the opportunities for electrical generation by enacting PURPA, rather than by attempting to limit the use and supply of electricity. To date, Congress's decision has proven to be very successful, as PURPA has made significant quantities of new electrical power available in the marketplace.

Congress is now presented with the opportunity to renew and enhance the policies set forth by PURPA. While supplies of electrical energy now generally appear to be abundant, industry analysts predict that this condition will not last. Therefore, Congress and the nation as a whole should take this time to assess our future energy needs and to prepare more wisely to respond to future energy shortages. The continuing development of the nation's small-scale hydropower industry can make a significant contribution and will remain an important element of our energy security.

The use of the natural energy supplied by falling water has always played an enormously important role in America's industrial development. During the Industrial Revolution, numerous low-head dams located along the East Coast harnessed power to drive factories and woolen mills. As people moved west, more massive dams were built by the Federal government, from Niagara Falls to the Columbia River, to supply electrical power to a growing population.

At the turn of this century, however, the prevailing view regarding electrical generation shifted toward, "the larger the facility, the cheaper the unit of output." Thus, utilities increased the size of their baseload plants from a few megawatts to hundreds of megawatts. Then, with the advent of cheap oil supplies, which appeared to be unlimited, many municipalities, utilities and industries systematically abandoned small-sized labor-intensive hydro stations.

After the enactment of PURPA, however, the small-scale hydro industry became the first renewable energy resource industry to gain momentum. The East Coast, one of the areas hardest hit in the energy crisis and most dependent on oil-fired generation stations, began the trend, as it turned to its many existing dams as a convenient, economical and environmentally sound source of additional electric energy. Since hydro generation is a simple and established technology, many existing facilities merely required rehabilitation. Many state and regional governmental bodies inventoried their own hydro resources and set plans in motion for the development or leasing of those resources. The Department of Energy funded feasibility studies regarding the rehabilitation of many one-to-fifteen megawatt facilities, and the Army Corps of Engineers conducted an inventory of existing dams to identify potential hydro sites. Books and magazine articles for the homeowner on micro-sized projects proliferated in the market.

In conjunction with its PURPA programs, the Federal Energy Regulatory Commission undertook rulemakings to streamline the complicated licensing process to help facilitate quicker development of small-scale hydroelectric facilities. New Hampshire was the first state to establish avoided cost rates implementing PURPA. It was followed by California and then the other New England states. While much of the early identification and development of hydro sites was undertaken by individuals and municipalities, even investor owned utilities began looking at rehabilitation of their own, previously abandoned hydro facilities.

STATE REGULATORY RESPONSE TO PURPA

The impact of PURPA upon hydroelectric development has varied significantly from region to region. Under PURPA, a public regulatory body in each state is required to identify methodologies for calculating avoided costs, establish interconnection standards and establish criteria for contractual arrangements between utilities and small power producers, while weighing the benefits and the risks to the ratepayers in the process. PURPA only provided a market for this power at wholesale, although some states have allowed limited retail sales under separate state authority.

Certainly, state-level implementation of PURPA has been uneven. The utilities' and the regulatory agencies' responses to PURPA have ranged from enthusiasm, to no action, to disdain. The states in most need of capacity were the ones whose public utility commissions thoughtfully, and in detail, developed fair and equitable avoided cost rates. Typically these were the states where the most small-scale hydro development occurred.

NHA strongly believes that there remain important issues regarding the development of small power production, but these can be best addressed at the state level. We urge that no attempt be made at this time to address these matters through changes to PURPA, or by other federal legislation.

Acknowledged Benefits to the Ratepayer

PURPA has resulted in diverse benefits to the electrical consumer. An insightful analysis of these benefits was recently provided by the Department of Public Utility Control of the State of Connecticut in its recent generic order on PURPA issues, which applies to hydropower. See Developing a Cogeneration and Small Power Production Infrastructure in the State of Connecticut, Docket No. 85-04-16, December 11, 1985. In that decision the Department stated the benefits to the ratepayer included:

> 1. No capital cost overruns paid by ratepayers. When a cogenerator estimates the cost of a project and negotiates a contract for payments to cover its debt and profit, it takes the risk that the actual capital costs will be higher than estimated. The price negotiated is the price paid regardless of actual capital costs being higher. The ratepayers are thus saved from the large cost overruns they have experienced with the recent utility central generating station projects.
>
> 2. No abandonment costs paid by ratepayers. If the construction costs make the project uneconomic, the technology does not work, or for any other reason the project cannot be placed in service, the [qualifying facility ("Q.F.")] project developer is liable for the project costs. The ratepayer pays nothing to the cogenerator for a plant that never became used or useful. For ratepayers who are still paying the costs of the abandoned Seabrook 2, Montague, and Pilgrim generating units, the benefits of this transfer of risks are clear.
>
> 3. Shorter construction lead times. Shorter construction periods have many benefits for utility ratepayers and investors. The utility investors will

not be at risk over long periods during which changing sales growth and fuel costs endanger the recovery of their investment. Utility ratepayers can benefit in that shorter lead times can allow the utility to respond more rapidly to changes in capacity need.

4. Reduce performance risks. Cogeneration projects by law are "must run" units like utility base load capacity (e.g. large nuclear plants). The ratepayer pays the capital costs and return on investment of such utility projects even if the unit is not producing any electricity. Under the pricing structure the authority approved in this Decision, the cogenerator or small power producer gets paid only if it is producing electricity and the price paid is greater when the system is in the greatest need of the electricity (i.e. during on-peak hours). The ratepayer has thus greater assurance of getting full value.

5. Reduced capacity reserve requirements. Because cogeneration and small power production facilities are smaller in size, the same aggregate Q.F. capacity requires a smaller amount of back up capacity. This is because it is less probable for one hundred 10 MW facilities to be out of service at the same time than two 500 MW facilities. An example of the impact of size of units on reserve requirements is the New England Power Pool ("NEPOOL") raising of the reserve requirements for its system utilities as a result of placement into service of the large Millstone 3 and Seabrook I nuclear generating units. Cogeneration projects will serve to reduce the reserve requirements and thus reduce the need for expensive backup power to assure reliability.

6. Miscellaneous economic benefits. There are other economic benefits as well to ratepayers and the State. Cogeneration may cause a business to stay or expand in Connecticut rather than leave the State to avoid high energy costs.

> Ratepayers also do not have to pay charges for construction-work-in-progress to cogenerators. The availability of cogeneration to meet system needs may enable the utilities to make a greater number of capacity and energy sales to other utilities. This will increase the economic benefits to the utilities from increased sales and NEPOOL savings shares. Id. at 12-13.

Full Avoided Cost Rates

The Public Utilities Commission of the State of New Hampshire recognized that many of the abandoned dams in the State could provide much needed sources of electricity to offset the State's heavy dependency on oil fired generation. It was the first public utility commission in the country to go forward with avoided cost hearings in 1979, and reaffirmed in later dockets, their commitment to the development of the hydropower potential in the State. See Rate for Small Power Producers and Cogenerators, Docket No. DE83-62, July 5, 1984.

The methodology that the New Hampshire Commission utilized was based on the calculation of marginal energy and capacity costs avoided by Public Service Company of New Hampshire (PSNH). In the Stipulated Recommendations in this case the Commission staff identified the following as the rationale for adopting a marginal cost method:

> An important objective is to utilize to the extent possible the same methodology, computer resources, and assumptions in rate proceedings for [small power producer] purchases that the Commission uses in rate proceedings for PSNH's retail sales. To the extent this is possible, several benefits will result, including consistency of assumptions, ease of understanding, reduced administrative costs, timely enhancements and reduced requirements for regulatory

> proceedings. . . . The economic definition of the marginal cost of electric service is the change in total cost of providing electricity as a result of a small change in load. The PSNH marginal cost methodology is based on the concept that load changes bring about changes in utility decisions, which in turn have an effect on utility costs. By identifying the consequences of the various types of utility decisions, marginal costs can be estimated. Id. at 6-7, Attachment I, 1.

Avoided cost calculations, such as that developed in New Hampshire, remain the most appropriate basis for calculating small power producer rates. Purchases at full avoided cost promote a level playing field, without increasing rates to retail customers. In the long run, by postponing the need for costly new facilities, and thus avoiding construction and financing costs, purchases from small power producers at avoided cost rates can actually mean substantially reduced electricity rates. In the short run, power purchases from small producers means that the electric utility, based upon its own cost estimates approved by the state commission, pays no more than it would have spent itself to generate the same marginal unit of electricity.

Despite various sweeping allegations, there has been no real substantiation that full avoided cost rates are having an identifiable detrimental impact on electric consumers. One point which helps to keep the impact of PURPA rates in perspective is that power sold to electric utilities from hydro and other small power producers still represents only a very small fraction of the total power transmitted through the nation's utility systems.

Purchases at full avoided cost are consistent with PURPA's goals and remain necessary to foster the development of small-scale hydropower and other small power production.

Despite the benefits of an avoided cost pricing structure, many hurdles and pitfalls remain for small power producers in financing their projects. Hydro development is particularly capital-intensive. Its special value is that it has no ongoing fuel costs over a very long life, but this is made possible only through substantial up-front investments. The existence of fixed and long-term avoided cost rates provides some of the assurance demanded by financial institutions, but achieving project financing remains a far from easy task for project developers.

SYSTEM RELIABILITY

A criticism that is sometimes leveled at small power production by the utilities is that it reduces system reliability, traditional operational modes, and line capability. However, there is simply no proof that this is the case. In fact, the utility sets the technical requirements for the interconnection design, the quality and grade of equipment, and demands whatever protection devices it regards as necessary to protect its transmission system. The interconnection agreement between the small power producer and the utility spells out liability responsibility, safety standards, over-and-under voltage line protection, substation disconnects and all the procedures dictating the technical activities between the producer and the purchasing utility. Under PURPA requirements, all the costs of the design, mechanical equipment, installation, and line upgrades for interconnection are borne by the small power producer.

Most public utility commissions require review and approval by their engineering staff of any interconnection agreement. These procedures ensure that the kinds of system reliability problems raised by the utilities cannot occur. Moreover, there are examples where small power producers actually enhance reliability. In many states, small hydro stations have been added in rural areas towards the end of a distribution line, thereby reducing the distribution line losses significantly. This has been recognized by a credit in the avoided cost payment formula, from such states as New Hampshire, Maine, Connecticut and Utah.

Many utilities have expressed concern over the potential for non-performance of small power producers as they begin to represent a greater proportion of the utilities' power supply. As the Connecticut order (Item No. 5) above indicates, a system with larger numbers of smaller, dispersed plants has a higher reliability factor than one which depends on a limited number of base load plants. The unplanned outages of so many nuclear facilities, and most notably the Three Mile Island accident, have demonstrated that even base load plants can be unreliable.

In small power production it is in the interest of the owner/operators to have the most efficient, reliable operation of their plant, in order to assure its maximum output. These plants generally operate within the constraint of a fixed price over their contract term for power. Their profitability depends on maximum plant production. Consider an example described by one NHA member whose hydro plant is located in the same watershed as one owned by a utility. During the winter, an examination of electrical production often reveals that the private owner/operator's production is much higher than that of the utility. Quite simply, it is in his interest to tackle the labor-intensive activities involved with winter operations, whereas the utility's hired personnel do not have that same incentive. To small-scale hydro operators, "water over the dam" has taken on new meaning.

COMPETITION

Electrical planning used to be a fairly straightforward business: consumption advanced at a rate of about 7 percent each year until the mid-1970s. At times, utilities, as regulated monopolies, were accused of living to build. As long as their investments--prudent or imprudent--were included in the base upon which their rate of return was guaranteed, the incentive was for them to invest. The energy crisis, however, brought in an era of conservation and the use of alternative energy, and electrical growth declined sharply.

Today utilities face new uncertainties in making growth projections. A recent report entitled "The Future of Electrical Power in America," by J. Hunter Chiles III for the current administration, predicted a 3 percent annual growth rate in electrical demand in the coming years. The report's predictions have received endorsement from the utility industry. In many cases, the addition of small increments of capacity will best serve the utility and consumers in meeting this reduced demand by creating a system capable of flexibility and increased reliability. Small power producers are best situated to provide these increments with the least risks to ratepayers.

A number of utilities have taken the competition from PURPA non-regulated power producers to heart, and have chosen to create subsidiaries to aggressively pursue this unregulated market. In the hydro community, this has been evident from the number of competitive applications between utilities and private developers over very small-scale sites.

At times an examination of the utility's cost figures suggests that its primary interest may have been in tying up the site, and preventing the private developer from gaining access. In Vermont, for example, there are three hydro stations located on one watershed, approximately ten miles apart. The most upstream site of 3 MW was built by a private developer at a cost of $5 million or $1600 per kw. The middle site of 4 MW cost the utility developer $12 million or $3000 per kw. The third site was three-quarters of a MW and cost a private developer under a million dollars or about $1200 per kw. The two private developers had to build their plants within fixed price contracts, while the utility project was built on a cost-plus basis.

Generally, however, the introduction of competition from small power producers is likely to have the healthy impact of encouraging efficiency, providing a new standard against which to measure utility efficiency, and yielding lower long-term consumer rates. If hydro and other small power producers are to have any chance to offer meaningful competition, it is vital that the full range of benefits and protections intended by PURPA remain in place.

Furthermore, if there is to be true competition in the wholesale marketplace for electrical power, access to the distribution system must be made available to the small power producer. Currently, only the utility servicing the location of the small power producer is required to purchase power from a small power producer. Since the location of hydro sites is dictated by the source of water, the supply of hydropower does not always match the demand. Access to wheeling would allow a utility which needs power to purchase power from a hydro site not in its franchise area, and to move from the area of a utility which claims to have excess capacity. The rates for wheeling should be set at a fair price, of course, and the guidelines already in existence for utility-to-utility purchases would be appropriate.

ENVIRONMENTAL ISSUES

Hydropower is one of the most environmentally benign energy sources known. Unlike combustion-based energy technologies, such as those using coal or wood, hydropower does not contribute to acid rain or other air pollution. And, of course, it poses nothing like the potential dangers to the public health and safety which exist as the result of nuclear-fired plants. However, as is now widely acknowledged, no form of energy production is without some environmental consequences.

Hydropower developers recognize that there are environmental impacts from the construction and operation of their facilities. However, mitigative measures can be undertaken during development activities which can remedy potentially negative environmental consequences. A hydropower project is also subject to rigorous environmental scrutiny during the FERC license application process. Currently, FERC regulations require approval of terms and conditions to be established by as many as 18 of the Federal and State agencies which can have authority over environmental activities.

Generally, opposition to hydro development has come from competing water users, purporting to represent the public interest. The environmental groups who oppose hydro development largely represent those concerned about the recreational use of water for sport fishing or boating. These interests are legitimate, but by no means do they represent the entire range of public interests associated with utilization of this nation's water resources. The "public" includes the millions of electrical consumers, as well as environmentally conscious citizens who are concerned about the impacts of competing sources of electricity, and who support hydroelectric development because it is a domestic, dependable, renewable, non-polluting and non-threatening energy source.

In their publicity campaign to oppose hydropower development, environmental groups at times have pointed to the thousands of permit applications filed with FERC since 1978. Their suggestion is that hydro development is rampant. They fail to point out, however, that a preliminary permit does not entail any environmental consequences, and that most permitted projects never actually reach the construction stage. The point which they most frequently overlook is that stringent environmental requirements already are in place, and effectively assure that the various competing public interests can exist side by side. Furthermore, stringent new environmental conditions and restrictions on PURPA projects involving new dams are contained in the recently passed hydro relicensing bills, HR 44 and S 426, and should address any additional concerns of the environmental community.

SMALL-SCALE INDEPENDENT HYDRO DEVELOPMENT SINCE 1978

Data on the numbers of projects and capacity that have come on line is not available from any single source. FERC's available hydro licensing data include numbers of licenses or exemptions issued since 1978, but does not indicate whether a project actually has been built. In trying to obtain data from public utility commissions, NHA discovered that often no differentiation is made between data regarding the hydro output of regulated utilities, municipalities and small power producers.

There are hundreds of projects in the development process which can be expected to produce new capacity in the next two to three years. For instance, New York State's Energy Office anticipates approval of over 100 licence or exemption applications in this year for projects whose size is 3 to 5 MW. Of these applications, only 20 are utilities representing a potential of over 300 MW of new independently produced power. The states shown below were able to provide limited data regarding hydro small power production:

	Project #'s	Capacity
California	78	51 MW
Colorado	9	8 MW
Idaho	27	11 MW
Montana	3	2 MW
New Hampshire	70	58 MW
Oregon	9	45 MW
Washington	18	70 MW

Hydro development has taken place in other states, but we were not able to obtain small power producer data.

CONCLUSION

The final results of PURPA are not yet in, but, thus far, the Act has been very successful. Numerous issues--such as the need to balance wildlife concerns with hydropower development requirements--have been raised and successfully resolved. The industry spawned around the resurgence of small-scale hydropower development has created new domestic manufacturers of turbines, generators, switching systems and automated control systems. Moreover, hydropower development has provided millions of dollars of construction work for engineering firms and contractors. Of far greater significance, however, is that the development of small-scale hydro under PURPA has brought new power that is safe, clean, and renewable--to the nation's energy picture.

The CHAIRMAN. Mr. Lyons.

STATEMENT OF MARK H.R. LYONS, ON BEHALF OF THE NATIONAL WOOD ENERGY ASSOCIATION

Mr. LYONS. Thank you, Mr. Chairman. My name is Mark Lyons, and I am director of contracts for Ultra Systems, Inc., which is a company deeply involved in the development, ownership and operation of alternative energy facilities, and one of the most successful developers of wood to electricity facilities in the Nation, facilities which we are now constructing or operating in Maine and California.

I am pleased to have the opportunity today to testify on behalf of the National Wood Energy Association concerning the critical role PURPA has played in bringing the benefits of wood electric generation to America's utility ratepayers, taxpayers, local communities, and others.

National Wood Energy Association was formed in 1979 to encourage public and private participation in the development of wood as a renewable energy source, and to provide a forum for communications regarding wood energy issues among commercial, institutional, industrial, and utility sectors.

Today, NWEA has nearly 100 members representing fuel suppliers, wood energy project developers, equipment manufacturers, and individuals.

The fundamental conclusion of my testimony is that where it has been actively and fully implemented, PURPA has been a great success. However, since its enactment in 1978, this piece of legislation has come under almost constant attack by the Nation's electric utilities, in the legislatures, in the commissions, and in the courts at untold cost to the ratepayers.

The fact is that there is no problem with PURPA at the Federal level and no changes in the law are warranted at this time.

The problem is that many utilities continue to reject the concept of competition in electric power generation and raise unending challenges to PURPA at ratepayers' expense in an effort to maintain their monopoly position.

It is our belief that this problem can only be solved over time, at the State level; by educating commissions and their staffs on policymaking in a climate of competitive electric generation; and by helping utility companies to overcome their fear of cooperating with independent power producers to the ultimate benefit of their ratepayers.

PURPA was enacted to address a series of specific problems that by the end of the 1970's had become rather severe for electric utilities. Although 1978 is not that long ago, there is a tendency to forget that at that time, many utilities were facing some serious problems. Many companies had embarked on a program of building very large, expensive powerplants, which regulators felt to be of dubious technology, while companies were running out of money necessary to bring these plants on line to meet large increases in load.

At the same time, in many cases, there was a need for smaller capacity increases in the short term and no capital was left because of the large commitment.

I think these problems could be summarized as difficulty or inability to conduct resource planning, inappropriateness or unfinanceability of the traditional options to meet load, and too much reliance on oil generation.

The big lesson at that time, and the situation that PURPA was designed to address, was that utilities were in fact no longer in control of the generation factor, so there was a conscious decision to let the marketplace work in this area.

The big question of 1978 was, were the megawatts there in alternative sources and could they maintain the quality of service that ratepayers had come to expect?

I think California is perhaps the premiere example in saying that the answer is "Yes." The theory of independent power has become reality and moreover, in large part, in 3 years since PURPA was enacted.

In short, we have done all we have promised in helping to solve the specific problems for which PURPA was enacted.

The megawatts are surely there; resources are in place in California, and in 1986, will generate 30 percent more power than Diablo Canyon. Morever, they represent high availability. On at least one occasion in northern California, QF's have continued to generate when the rest of Pacific Gas and Electric grid tripped off.

These facilities are characterized by short construction leadtimes, in most cases 2 to 3 years as opposed to 20 years for Diablo Canyon, and they are built in small chunks. Both of these factors help to narrow the margin for error in resource planning.

They have also certainly reduced reliance on imported oil.

Wood energy is a technology that provides the full range of benefits of independent power. It is a proven technology. It can offer energy and capacity on a spot basis, or pursuant to a firm commitment, and it has high capacity value to the utility. It is both dispatchable and the fuel is readily available and at fairly stable prices.

Moreover, independent power producers in general, and specifically wood energy, provides other benefits to the ratepayers, not necessarily as ratepayers, but as members of the local community. These benefits for wood energy can be divided roughly into environmental benefits. Where we burn waste wood we are correcting a known, existence of specific environmental problems. And our plants also provide tangible local payback to the local community in terms of jobs, and we have estimated conservatively that for every kilowatthour our plants generate, 4 cents per kilowatthour is paid back to the local community.

These benefits have been particularly helpful in increasing the competitiveness of the paper and sawmill industry, and they also tend to be focusing in rural American where unemployment has been running above the national average.

It has been my experience, the utilities don't like to talk about the association benefits, even though they claim to hold the interests of ratepayers above all others. But the fact is, that the people in these communities are in fact ratepayers of the utilities.

As has been mentioned several times by this panel, PURPA is not easy to implement. It requires intellectual resources and a willingness to change well established mindsets. Where PURPA has not worked, it is because there has been constant opposition to its full implementation as it is defined in FERC regulations.

The opposition has been both explicit and implicit. It is not difficult to recognize the explicit opposition. It usually comes in the form of summons and complaints and is very often at the expense of ratepayers.

I think what is perhaps more dangerous and perhaps insidious is the input of the opposition that has been placed against PURPA. Let's face it, PURPA was designed to change the system and not perpetuate it.

Any kind of delay or lack of responsiveness to putting a program in place works in favor of established interests and against decentralized, heterogenous industries that was, and continues to be, an unknown quantity in the financial community.

Where PURPA has worked it has been because regulators have flinched in the challenges of avoided cost ratemaking and have set a priority, encouraging QF development.

Perhaps a key aspect of successful PURPA programs is the series of meaningful power sales agreements. This is particularly true of the programs in California and Maine where there are now in place long-term contracts which do in fact fairly compensate independent power producers for the full measure of costs they have allowed utilities to avoid, which includes the total costs of new baseload capacity.

Moreover, it is important to note that in each case, these power sales contracts insulate the ratepayers from risk in two very important ways. The first is that they rely on avoided cost prices, which by its very definition, means that the QF is paid no more than the cost the utility itself could generate without the existence of the QF.

And the second important way that these contracts insulate the ratepayers from risk is that, by their terms, the QF's are not paid unless they produce power.

We have heard comments from the previous panel about the obscene profits that have been reaped by the QF developers, and I think it is important to point out that the issue here is not who is making more profit, but if it is, if we are going to widen to that scope of inquiry, then I think it is important to compare fairly the profits that are being made by QF's and the profits being made by utilities.

The fact is, that the QF industry is a deregulated, competitive industry, and our money markets say that where there is risk, there will be reward. It is a fact of life in financial markets that there is a higher rate of return for independent power projects that for utility's own investment.

In California, the utilities are in fact earning between 15 and 16-percent return on investment, with practically no risk at all. Moreover, I think it is important to point out that Southern California Edison, on whose behalf we heard testimony before, is not only one of the most successful investor-owned utilities in the country, but also owns a rather successful QF development subsidiary.

I would like to echo the comment of Mr. Morris previously, to the effect that we, as a company, have also had the opportunity to negotiate contracts with the utilities on a shared-savings basis, and as company to company, rather than on a strict PURPA basis. We welcomed that opportunity and we will welcome it in the future.

I think it is also very important to point out that without PURPA in place, the utility in that case and in others would have no intention to negotiate.

Finally, I think it must be pointed out that the very thing that has made the PURPA program successful in the States where it has worked, and that is long-term contracts that reflect long-run avoided costs, will be of indispensable value in helping utilities cope with two of the biggest problems they face now and will face in the future; that is, the need to avoid the building of new capital intensive baseload plants, and the need to avoid system bypass. That is, to the extent that QF's are committed to sell their output to the utilities under fair long-term contracts, this will help reduce the risk of system bypass.

In summary, I would like to say that there is no reason to change PURPA at the Federal level, and certainly no crying need for legislation which would warrant diverting congressional attention from more pressing issues.

PURPA is an experiment that is working, and I believe if the new standards for pricing were put in place at this time, it would take commissions another 8 years to catch up, not to mention the renewed incentive for explicit opposition from utilities.

Rather, I think PURPA should be kept in place as it is, to help create consistency and stability in the independent power market, and lend a greater body of experience as to how PURPA can continue to work for the benefit of ratepayers in the future.

This concludes my remarks, thank you.

[The prepared statement of Mr. Lyons follows:]

TESTIMONY
ON
IMPLEMENTATION OF THE
PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978
SUBMITTED TO THE
U.S. SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES

JUNE 3, 1986

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My name is Mark Lyons and I am Director-Contracts for Ultrasystems Incorporated, a company deeply involved in the development, ownership, and operation of alternative energy facilities and one of the most successful developers of wood-to-electricity projects in the Nation.

I am pleased to have the opportunity today to testify on behalf of the National Wood Energy Association concerning the critical role PURPA (the Public Utility Regulatory Policies Act of 1978) has played in bringing the benefits of wood electric generation to America's utility ratepayers, taxpayers, local communities, and others.

The fundamental conclusion of my testimony is that, where it has been actively and fully implemented, PURPA has been a great success. However, since its enactment in 1978 this piece of legislation has come under almost constant attack by the Nation's electric utilities -- in the legislatures, in the commissions, and in the courts -- at untold cost to their ratepayers. The fact is that there is no problem with PURPA at the federal level and no changes in the law are warranted at this time. The problem is that many utilities continue to reject the concept of competition in electric power generation and raise unending challenges to PURPA at ratepayers' expense in an effort to maintain their monopoly positions. It is our belief that this problem can only be solved over time at the state level, by educating commissions and their staffs on policymaking in a climate of competitive electric generation, and by helping utility companies to overcome their fear of cooperating with independent power producers, to the ultimate benefit of their ratepayers.

The National Wood Energy Association (NWEA) was formed in 1979 to encourage public and private participation in the development of wood as a renewable energy source and to provide a forum for communication regarding wood energy issues among the commercial, institutional, industrial, and utility sectors. Today NWEA has nearly 100 members representing fuel suppliers, wood energy project developers, equipment manufacturers, and individuals.

My company, Ultrasystems Incorporated, has been designing and constructing advanced energy projects for the past 16 years. In 1982 Ultrasystems formed a subsidiary company, Ultrapower Incorporated, to develop, own, and operate small power and cogeneration facilities. Since then, Ultrapower has brought on line three 11 MW waste-wood-fired power plants in northern California. We also have a 25 MW fluidized-bed wood facility about to come on line in California and two similar 25 MW plants under construction in the State of Maine. Finally, we have two more 25 MW waste wood projects and two 37 MW coal-fired cogeneration facilities in the advanced stages of development in California, for a total of 232 MW.

Title II of PURPA was enacted to provide an alternative to the traditional method of developing electric generating capacity in this country. By the end of the 1970's it was becoming clear to many that the old way of providing electric power was no longer suiting ratepayers' needs.

Electric utilities had embarked on aggressive construction programs to build bigger and bigger central station power plants to meet what they assumed would be a demand growing at historic rates -- but demand stopped growing as fast as it had. Moreover, the key technology that utilities were relying on to meet these assumed loads -- nuclear power -- failed to gain the full confidence of those charged with regulating its safety aspects and utilities found themselves redesigning their projects while they were under construction, causing costly delays. While utilities were running out of money trying to complete increasingly costly plants to meet unrealized demand, the running costs of existing generating capacity skyrocketed with the oil crises of 1973 and 1979. As a result, ratepayers for the first time in memory began to reject their utilities' kilowatt-hours in favor of investments in conservation, electricity substitutes, and self-generation.

The theory beyond Title II was sound and simple. Aware of the existence of vast resources of alternative energy and the availability of the technology required to convert these resources to electric power, Congress determined to remove the most significant barrier to bringing this power to market. Electric utilities had shown little or no interest in developing alternative energy sources in the past and for many companies all capital had already been committed to traditional generating options.

Moreover, most utilities refused to purchase power from outside generators at a fair market price and private parties were reluctant to invest in electric generation for fear of becoming regulated.

PURPA allowed private capital to enter the electric generating sector by opening the utilities' monopoly to independent small power producers and cogenerators. By its terms, PURPA required utilities to purchase this power at their own avoided cost so they would resell it to their own ratepayers, thereby retaining their existing customers base.

Since its enactment, PURPA has faced almost constant legal challenge from utilities, which has delayed its full implementation. Moreover, the fundamental changes PURPA implies to the traditional ways in which utilities and their regulators have done business have required a re-education which is time-consuming even for those who want to comply with its directives -- and many still do not. Thus, in a majority of the states there is still no meaningful PURPA program, even after eight years, and ratepayers in these states have yet to realize the benefits of independent power. It seems that the utilities and regulators in such states believe the problems they faced in the 1970's were a one-time occurrence and that eventually they will be able to return to business as usual.

But for those who have embraced the challenges of PURPA, and have not flinched from the brave new world of independent electric generation, the rewards have been profound. Moreover, in such states these rewards have been realized in a much shorter period than the 8 years since PURPA was passed. California and Maine stand as premier examples of states in which PURPA has been fully and effectively implemented. The following discussion draws specifically on the California experience.

In 1982 the California Public Utilities Commission embarked on an ambitious program to fully implement PURPA by establishing a series of standard contracts by which its jurisdictional utilities would purchase energy and capacity from "Qualifying Facilities" ("QF's") at the utilities' full avoided costs.

Today there are almost 600 independent energy producers on-line generating reliable electric power for California's ratepayers. In 1978 independent power production was still a theory and many people doubted it could ever make a substantial contribution to the Nation's electrical needs. But in 1986, California's independent energy producers will generate 30% more power than the state's newest baseload power plant, Diablo Canyon. Through the efforts of California's regulators, utilities, and electrical entrepreneurs, independent power has indeed become a reality.

The fact that independent power producers will provide more energy than a large central station plant, however, is only part of the story. In fact, these qualifying facilities have also helped substantially to reduce the state's dependence on oil and gas, and they were built in a fraction of the time it took to bring Diablo Canyon on line and in smaller increments -- which has helped California's utilities narrow the margin for error in resource planning. Moreover, the dispersed nature of QF capacity (that is, building in smaller "chunks") inherently increases its reliability and provides the potential for meeting a variety of site-specific needs on the existing electric grid.

Perhaps most significant, however, the growth of this independent power sector has provided real competition to the utilities' own generation and a tone incentive to minimize its future generating costs.

One of the most important aspects of California's PURPA program is the way its standard power purchase contracts have served the needs of all QF technologies, allowing them the option to provide long-term, firm energy and capacity as well as energy and capacity on an "as delivered" basis, while insulating ratepayers from risk. The portfolio of standard offers in California allows some independent generators to deliver power on a spot basis pursuant to an incremental energy rate option, and the price paid for such energy rises and falls with the utilities' current marginal operating cost. At the same time, other QF's who can maintain minimum capacity levels provide firm capacity over a long term at a pre-established price. This mix of pricing options, which precisely reflects the directives of the Federal Energy Regulatory Commission's rules under PURPA, has resulted in a lowering of the utilities' marginal costs in the current time frame while also allowing them to avoid new baseload construction in the future.

Moreover, all of these benefits have been achieved without any risk to the ratepayers, either in building this new capacity or in running it. For while California's QF's have demonstrated extremely high reliability, even if one or more QF's do not run from time to time the ratepayers incur no cost because under their contracts these QF's are only paid for the power they produce.

Wood-fired power plants are a QF technology that can provide the entire range of benefits exhibited by independent energy producers. They displace fossil fuels, and can provide energy and capacity on a spot basis or pursuant to a long-term capacity commitment. The ability to provide from energy and capacity from wood-fired facilities results from two key factors: The technology is proven and dispatchable, and waste wood fuel is readily available.

There is nothing esoteric about wood energy. Wood has been an important source of fuel for industry in the United States throughout the past century. Its use diminished drastically during the middle of this century due to the availability of cheap oil and relatively low electricity prices, but it became a significant fuel candidate again in the 1970's because of the oil crises of that decade.

The forest products industry has traditionally been the largest user of wood energy, and is approaching energy self-sufficiency from wood for its thermal and electrical energy needs. Wood and biomass usage including home heating has grown from approximately 2.0 quads to almost 3.5 quads over the past decade. From the larger user prospective there are well over

3,000 commercial industrial and utility combustors fueled primarily with wood in the United States today.

Moreover, the potential from growth in the use of wood for energy is enormous. This potential is not from clear-cut timber, but rather from dead, diseased, and other waste wood. As President Reagan pointed out in a radio commentary he delivered in 1979, in which he described his own personal involvement and belief in wood energy,

> ...about five billion tons of fiber is wasted each year as trees die or become old and cease to increase in size... This five billion tons of waste wood is the equivalent of eight-and-a-half billion barrels of oil.

The technology for converting this vast supply of waste wood into useful forms of energy is well known and has been around for years. However, with the rapid growth in wood energy applications since the oil crises of the 1970's and the passage of PURPA, wood energy technology has advanced considerably. Two examples are fluidized-bed boilers, which allow for the burning of wood waste in virtually any form, size, and quality in an environmentally-acceptable manner, and wood gasification technology, which converts solid wood fuel into methane gas for those many applications in which a clean gaseous fuel is more appropriate.

Among its valuable features, wood energy technology provides several distinct environmental benefits. Waste wood is a beneficial fuel when it is properly combusted and an environmental nuisance when it is not. As an example, Ultrasystems' wood-fired power plants draw wood waste from four primary sources, in each case providing a valuable environmental benefit.

When we draw dead, diseased, and low-grade wood from the forest, in association with traditional logging operations, we provide a market for a waste material which otherwise would stunt the growth of high-grade trees, spread disease, and cause and exascerbate forest fires. In several of our plants we will burn agricultural wastes, prunings, and trimmings from orchards and vineyards, which would otherwise be open-burned, generating nothing but air pollution. Our plants will also burn municipal wood wastes which would otherwise be crowding scarce landfills. Finally, we burn waste by-products from sawmill operations in areas where these materials have no alternate market, which not only provides an environmental service, but also enhances the competitiveness of America's sawmill industry.

In addition to these specific environmental benefits, wood energy technology provides many new local jobs -- Ultrasystems estimates about 75 new jobs for each new plant it develops, in operations and fuel procurement -- and generally helps keep energy dollars at home. In fact, under reasonable assumptions we have estimated that for each kilowatt-hour our plants generate, about 4¢ is returned to the local community in 1986 dollars, and this "payback" will increase with inflation.

Finally, one of the most significant aspects of wood energy projects is that the economic benefits they provide are focused on rural regions, where unemployment has been running above the national average.

In conclusion, PURPA has been instrumental in reversing some of the critical problems that have faced our electric utility industry in recent years. The California experience shows that where utilities and their regulators have embraced rather than rejected the challenges of this important legislation, independent power facilities such as wood energy projects have proliferated and great rewards have been realized to the benefit of ratepayers. Moreover, it is becoming increasingly clear that through a consistent active implementation of a PURPA program today's utilities can continue to rely on independent power not only to avert a recurrence of past problems in the future, but to help prevent new ones. By offering fair avoided-cost prices in long-term contracts, electric utilities can attract QF's to make firm commitments of energy and capacity, helping to avert system bypass and a loss of existing customers, while minimizing the need to risk their own capital on new baseload construction. If the Nation's electric utilities and their ratepayers are to truly realize these benefits, PURPA needs to be allowed to work, not changed.

NWEA NATIONAL WOOD ENERGY ASSOCIATION

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BENEFITS OF WOOD ENERGY COGENERATION AND SMALL POWER PLANTS

The National Wood Energy Association (NWEA) has long been involved in the responsible, environmentally-sound development of the wood energy industry. NWEA's emphasis has been on both wood energy supply and demand issues relating to the commercial, institutional, industry, and utility sectors.

During the 1970's, the major growth in wood energy applications came as a direct replacement for higher-priced oil or natural gas in commercial, institutional, and industrial markets as well as for home heating. During the 1980's, a major new wood energy market has arisen for the industrial and utility markets in offsetting higher-priced electricity. In general the electric power applications of wood energy in the 1980's are larger in scope than the steam and thermal applications of the 1970's; and they are proving to be active ambassadors for wood energy.

Questions are often asked about the benefits of wood energy. For that reason NWEA has summarized the following economic and social benefits, most of which hold true for all wood energy projects, but some of which are particularly true for electrical power production projects. These social benefits generally fall into three categories: Economic; Environmental; and Energy Independence. They are substantiated by a number of actual projects, developed by a number of different companies in several different states. The benefits described below are most specific for wood energy projects in the nominal 5-30 megawatt (MW) size range -- projects large enough to have significant positive impacts, but not so large that they might introduce negative impacts.

ECONOMIC BENEFITS

New Jobs - Wood energy is a labor-intensive industry, given even constant improvements in the efficiency of in-forest harvesting and wood-processing equipment. The combination of power plant operators, loggers, and truckers generally yields direct new jobs of between 3-5 jobs per MW of power production. Thus, a 10 MW project might yield 50 new jobs, while a 25 MW project would yield close to 75 new jobs for the life of the plant -- ordinarily 30 years. There are 100-200 construction jobs during the 1½- to 2-year construction period of major power plant facilities. Commercial-scale applications of wood energy create proportionately fewer new jobs, but are nevertheless net job creators.

Tax Revenues - Wood energy projects yield direct new tax revenues in three forms: Sales taxes: personal income taxes; and property taxes. Sales taxes vary by state, but are always paid on equipment and oftentimes on fuel. Personal taxes are paid at the state and federal levels for both construction personnel and ongoing operations personnel. Property taxes are paid on the multimillion-dollar plants, quite often dramatically increasing the local tax base. Several recent studies compared the 10% Energy Tax Credit (ETC) benefit which a project might receive (at least to the U.S. Treasury) with the direct new tax revenues generated. It was found that there were two to three times more new, direct tax revenues generated during just the construction phase than for the ETC received by the project.

Electricity Rates - Despite the fact of currently decreasing oil prices, wood energy most often replaces more expensive oil-generated electricity. Whenever that happens, there is a direct benefit of 3-5¢/kilowatt hour (kWh) for oil that does not have to be imported into the country or to the given utility service area. This fact is equally true for other renewable energies such as hydro or solar. However, when wood energy is used, there is an additional benefit of 4-5¢/kWh, representing the direct payments made for salaries, fuel procurement, property taxes, and certain maintenance costs which stay within the local community where the power is being produced. Few, if any, other energy forms can make such a claim on a wide-scale basis. Such benefits might be seen as a form of local "rebate" to ratepayers who receive few (if any) direct economic benefits from oil, gas, coal, or nuclear power facilities.

Forest Improvements - Throughout the North American continent there is generally solid agreement among foresters and land managers that the removal of low-grade wood from the forest yields demonstrable economic benefits. In particular, the wood energy industry makes possible long-term and regular removal of unmerchantable/dead/diseased/damaged trees or thinning of overdense stands. This results in improved growing conditions and the opportunity for better species which means more valuable forests. Such benefits have already been tested and experienced by major public landowners, including the U.S. Forest Service; large private landholders, such as the forest products industry; and small woodlot owners.

ENVIRONMENTAL BENEFITS

Air Emissions - Wood has essentially zero sulfur content which makes it a high-preference fuel with respect to acid rain concerns. Other emissions are generally well below the safe state and federal air quality limits.

Emissions Offsets - Waste wood combusted in modern high-pressure boilers is highly preferable to open burning of forest residues or agricultural wastes by planned or accidental means; and net improvements in air quality are achieved with some projects. There are also significantly greater environmental efficiencies compared to residential wood burning.

Beneficial Ash - Wood ash is a low-grade fertilizer with no toxic or hazardous components. In many projects the ash is being directly applied to nearby agricultural lands as a soil amendment.

Landfill Life - Local landfill lives are extended in many cases by using the wood waste components of incoming materials.

Forest Aesthetics - Improved forest land management through thinning enhances the aesthetics of the forest, as well as its economics. Proven harvesting guidelines also ensure acceptable soil nutrient maintenance and wildlife habitats. Related benefits include improved water quality, mitigation for tree diseases and insect damage, and higher utilization of existing forest land.

Fire Safety - Removal of a significant fraction of the slash material generated by conventional logging operations will reduce forest fire potential. Fires are often fed by the slash on the forest floor.

ENERGY INDEPENDENCE

Imported Oil Offsets - Each megawatt of power produced from wood offsets well over half a million gallons of oil imports annually. Thus a 25 MW plant would offset more than 13,000,000 gallons per year or over 300,000 barrels per year of oil imports. The same holds true for thermal energy produced from wood. Such lesser dependence on foreign oil is one of the reasons that current oil prices are lower, and it further reduces the probability of future oil crises such as those in the 1970's.

Imported Electricity Offsets - In some parts of the Nation, imported electricity is becoming the path of least resistance for electric utility companies' demand growth. While near-term prices may be attractive, long-term prices and questionable reliability may prove more costly. Wood power plants can provide reliable, economically predictable power for decades.

Improved Electrical Performance - Smaller, dispersed alternate energy projects clearly improve electric energy reliability in given utility service areas. There is less chance of blackouts in a given local area, and there are line efficiency improvements when power from a central station doesn't have to be transmitted over long distances.

Utility Flexibility - New power is needed in many sections of the country over the next decade which will not be supplied by conventional coal or nuclear central station plants because of weakened utility finances; long lead times (6-8 years lead time for coal, 10-12 years for nuclear); and uncertainties in traditional load forecasting. Small wood-fired energy projects can be built to provide power when the utility needs it (2-year lead times); where the utility needs it (strengthens the grid); risk free to the utility (private financing used); sized to hedge the growth uncertainties; and generally freeing the utility to strengthen its increasing service role.

Indigenous Renewable Resource - Energy produced using indigenous, renewable resources is an obviously positive step toward energy independence. This is true for locations with wood, coal, geothermal, wind, hydro, and solar resources. However, wood appears to be one of the most abundant renewable resources and is found almost everywhere in North America from forested areas, to agricultural areas, to urban areas.

The end result of all these considerations is this: The benefits from renewable wood energy are undeniable. There have been many attempts to find an Achilles' heel for broad-scale wood energy applications in the commercial, institutional, industrial, and utility sectors, but wood energy is now standing the test of time in modern America just as it did in the past. Wood is not only good; but because of its collective economic, environmental, and energy independence benefits -- it is hard to find a fuel that can equal the benefits of wood energy.

Bob Kennel
President
NATIONAL WOOD ENERGY ASSOCIATION

The CHAIRMAN. Mr. Caldwell.

STATEMENT OF JAMES CALDWELL, ON BEHALF OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION

Mr. CALDWELL. My name is James H. Caldwell, Jr. I am the president of Arco Solar, Inc. My company designed, constructed, owns and operates the two largest operating photovoltaicly powered qualifying facilities in the country. In addition, we supply the photovoltaic cells for the majority of this country's grid interactive photovoltaic installations.

I am here representing the Solar Energy Industries Association, which is the national trade association for solar, thermal, and photovoltaic manufacturers.

Our association strongly endorses PURPA as a vehicle for encouraging innovation in electrical power generation and diversifying the supply mix of this Nation's electric utilities.

Solar powered qualifying facilities utilize several variations of two basic technologies: photovoltaics, the direct conversation of sunlight to electricity; and high-temperature solar thermal, the use of concentrated sunlight to generate steam to drive a conventional turbine generator.

Without PURPA, or least the guarantees of its basic tenets, that is the right of interconnection and a fair and reasonable price for the produce, very few if any of these plants would have been constructed. Certainly, by this definition, PURPA has been successful. We have collected valuable experience with two potentially important future technologies, and, moreover, even the demonstration plants are paying their own way with clean, low operating cost electric power.

It is true, the construction of these plants was publicly subsidized; that is, all of them received the benefits of Federal energy tax credits. I do not believe that any apologies or explanations are required for this fact. However, I do believe it is important to say that none of these plants receive any form of subsidy from PURPA, or the ratepayers of the connected utility.

The ratepayers are totally unaware that the electrons flowing through their household wiring are there because the Sun shone on equipment in a field, and they neither gain nor lose financially because an entrepreneur, rather than a local utility, owns that equipment.

I believe it is also important to say that all of these plants were constructed and are operating with the cooperation of the local utility. PURPA may provide the framework for the contractual relationship between the utility and the facility own, since by definition, negotiation with a monopoly is, well, rather difficulty, but prudent, long-term business relationships are not made by one-sided contracts.

Any long-term contract in any industry will have periods during its term where one side is favored over the other, but the worm turns quickly. Anybody in business understands that the today's sticker is hoist on his own petard tomorrow. It works wonders for common sense and reason in situations like that.

PURPA then has worked just fine, thank you. It is not PURPA's fault that avoided costs are easy to define but difficult to measure. There is no reason to believe that it should be any easier to deal with avoided costs than any other regulated cost concept. PURPA was certainly not meant to replace regulatory commissions and common sense.

It is not PURPA's fault that these avoided costs increased by 50 percent, then leveled off, and then dropped by about one-third all in the space of 7 years. As you might expect with an economic theory, that is less volatile than the oil prices during that period.

It is not PURPA's fault that surpluses and deficits in electric generation capacity exists simultaneously. Neither, on the other hand, is it PURPA's fault that only 100 megawatts of solar electric generating capacity—that is about one-fourth of a singular, modular small coal-fired power plant have been installed.

Our own industry cost structure seems to have more to do with that fact.

When painting with a broad brush, then it is rather difficult to find any fault with any part of the legislation. It is only when you examine individual cases at specific times that the warts begin to show.

Ironically, though, most of the problems recited this morning would have been easier to solve by expanding the scope of the law, that is, by giving the parties who knew more about the situation more latitude, not by rolling back the provisions of PURPA. Now I am not necessarily advocating unrestricted wheeling, or unrestricted ownership or primary transmission common carrier status, or any of the other kinds of deregulation concepts that are currently in vogue.

But, please, PURPA was not the work of the devil. It was not and is not a grand, sweeping change in the electric utility industry structure. It was and is a halting, modest, ex post facto legislative recognition of economic reality. It didn't lead; it followed the reality of a permanent change from a declining cost industry to an increasing cost industry, and of a permanent change of the reality of new technology and new economics that dictated new solutions.

Let's leave it alone. Thank you.

[The prepared statement of Mr. Caldwell follows:]

SEIA

SOLAR ENERGY INDUSTRIES ASSOCIATION Suite 503 1717 Massachusetts Avenue, N.W. Washington, D.C. 20036 (202) 483-6225

TESTIMONY

by

JAMES CALDWELL
PRESIDENT
ARCO SOLAR INC.

for

SOLAR ENERGY INDUSTRIES ASSOCIATION
WASHINGTON, D.C.

before

SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

June 3, 1986

WASHINGTON, D.C.

SOLAR ENERGY INDUSTRIES ASSOCIATION

INTRODUCTION

In 1978, the U.S. Congress passed the Public Utilities Regulatory Policies Act (PURPA) which provided the opportunity for small energy producers to interconnect into the utility grid and to be paid a fair and reasonable rate for the power they produced. This section of PURPA was created at a time when the Congress was considering a broad range of energy initiatives to encourage domestic energy production--particularly a diverse set of alternative and renewable energy sources in response to the oil embargo.

The Solar Energy Industries Association (SEIA), the national trade association for solar thermal and photovoltaic manufacturers and component suppliers, strongly endorsed PURPA as a vehicle to encourage solar energy utilization by this nation's utilities. PURPA has effectively encouraged utilities throughout the nation to use solar thermal power and photovoltaics for peak electrical production.

With the temporary expiration of the commercial solar tax credits and temporary lower prices of petroleum, SEIA believes attempts to impede the right of solar companies to interconnect with the grid and to be paid a fair rate for their power, would be extremely harmful to the nation's solar industry. In addition, such attempts would effectively harm the consumers' future security of having energy produced from solar energy domestically rather than imported energy.

The Solar Energy Industry Association and our solar companies are aware of the concerns about the effectiveness of PURPA. However, we maintain that none of these problems were created by the solar industry, and that all of these problems can be corrected at the state level.

SUCCESS OF PURPA

The solar energy industry is a very young industry. Although photovoltaics resulted from our need for electricity in the space program, the photovoltaics industry truly became "commercial" in the late 1970's and, frankly, has only begun to make market inroads in the 1980's. This is essentially also true for the solar thermal power industries which produce electricity by converting solar heat to steam. Both industries have relied on PURPA to become established domestically. Due to PURPA, this nation has some prime examples of solar/utility cooperative projects that would not have happened otherwise.

According to 1984 U.S. Department of Energy figures, coal produces 14 quads of electricity, nuclear and natural gas provide about 3 quads each, and petroleum between 1 - 2 quads. Renewable energy provides almost 4 quads of electricity, with solar accounting for less than 1 quad of electrical generation. In 1982, solar did not provide any direct electricity to the grid. But by 1985, solar thermal power and photovoltaics have produced 104 megawatts of power.

In 1983, photovoltaics provided 225 kilowatts of electricity for the Sky Harbor Airport near Phoenix, Arizona. In 1983, my company completed a photovoltaic power plant producing one megawatt of electricity for Southern California Edison. By 1984, La Jet Company installed 700 dishes that provide 4.4 megawatts of power to San Diego Gas & Electric. 1985 was auspicious for the solar industry because Luz Engineering completed a 14.7 megawatt system for Southern California Edison and architect John Long completed the first photovoltaic housing development where 3,600 photovoltaic panels provide electricity for twenty-four homes with the additional electricity sold to the Salt River Project (utility). And finally this April came the dedication of Luz's second solar thermal power plant, which will produce 30 megawatts for SCE. With the right of interconnection into the utility grid and the required payment of a reasonable rate for power, PURPA has made these projects successful.

ISSUES OF CONCERN

Interconnection. Section 222 of PURPA requires that small power producers have the right of interconnection. The law limits this right of interconnection if the utility in question has enough power to meet its consumer's needs. Arguments by some utilities that PURPA encourages over-capacity are untrue. State utility commissions have the responsibility to implement PURPA, and it is through each state's hearing and review process that determinations of these capacity questions are made. Indeed, if a state utility commission determined that a proposed PURPA project would cause over-capacity, it could block such a project under the current law. Unfortunately, over-capacity issues involve much more than the production of power by small power producers. Often issues such as changes in consumer demand and the wheeling of energy play far more of a role in over-capacity questions than does PURPA. Even under the most optimistic predictions, photovoltaics and solar thermal power together could not generate enough energy to push any utility into over-capacity through the year 2000. Many utilities who claim that PURPA creates conditions promoting over-capacity, are the same utilities that have approached the U.S. Department of Energy for assistance in order to prevent possible electric shortages in the approaching decades.

The Solar Energy Industries Association maintains that the provisions of PURPA requiring interconnection of small power producers are absolutely necessary and would severely harm the potential of solar projects if removed or weakened. The current law has worked well, and the only problems have been state utility commission determinations in specific projects which will be discussed later in this testimony. However, as long as small power producers have the right to an interconnection if they bear the cost of that interconnection, and limited by the capacity of the utility, solar energy will continue to provide more energy in our nation's utility grid.

Avoided cost. After two years of hearings, the Federal Energy Regulatory Commission (FERC) developed a process to implement the "fair and reasonable" rate requirements of PURPA. The avoided costs concept was simple enough--small power producers should be paid at the rate that a utility would have to pay to bring into production or on-line new electricity. This avoided cost rate would be determined by state public utility commissions. Each state currently determines the avoided cost rates through different processes and formulas and at different times.

Very few, if any, solar projects are paid at the full avoided costs rates for their electricity. In many cases, solar producers accept lower rates in return for longer contracts as a way to obtain financing. In other cases, the states average the cost of new electricity from different sources of energy--coal, nuclear, etc.--and the avoided cost rate is usually lower than if the utility were actually producing electricty from a new plant. In southern California, the avoided cost rate is 4.3¢ per kwh while the utility in San Diego is purchasing electricity from neighboring Arizona at over 14¢ per kwh.

The avoided cost principle adopted by FERC after two years of hearings, has been attacked in every way. In the U.S. Court of Appeals, several utilities charged that FERC overstepped its authority in establishing an avoided cost requirement when all the legislation required was a fair and reasonable rate. However, the U.S. Supreme Court rejected that notion and the final impediment to implementing PURPA was eliminated. Now many utilities have charged that the avoided cost concept hurts consumers because it requires utilities to charge their consumers the top rate for power. The solar industry can cite far more examples of solar electricity bought well below the avoided cost rates to achieve long term contract arrangements, or substantially lower than the power utilities purchase from utilities in other states. The avoided cost concept, the FERC interpretation, and the actual practice protect the consumer adequately. Although some state public utility commissions may not implement PURPA as we would like, the federal law provides ample protection for consumers so that they receive lower cost energy. Although at times a utility may be able to obtain or produce "lower than avoided cost" electricity, over the long run the utility saves consumers much money from not having to build capital intensive production plants that, in many cases, are not producing to capacity.

State Implementation. By leaving the regulations to state implementation, PURPA has not been a panacea for the solar industry. Although the Administration has promoted a move of federal authority to state implementation, this approach in other solar programs and even with PURPA has had its share of problems. In concept, each state should have control of the power mix and the trade-offs between the needs of utilities and the needs of consumers. This is no easy task--particularly in the recent energy environment of changing consumer attitudes, see-sawing energy prices and financing issues, among others. However, any program is as good as its implementation. State utility commissions that support a mixed and balanced energy production scenario in their state, support PURPA more positively than state commissions that see small power production as a nuisance.

For instance, some utility commissions have required an annual capacity factor threshhold in order to be a qualified facility (QF) to interconnect. However, most solar power is used for peak power. Therefore, if a solar facility has a capacity factor of 95% during peak power times but only 30% in off peak, most in the solar industry strongly assert that interconnection should be encouraged. However, California has at times requested a 60% overall annual capacity factor even though solar plants could not meet that requirement. In certain cases this requirement has been waived. But it is just this kind of impediment that SEIA believes departs from the intent of PURPA. Although the solar industry does not always agree with all utility commission determinations, SEIA believes that state review is a situation with which we must live. Most of the concerns and complaints about PURPA involve state interpretations. But as with any federal program, states are having more and more control over federal funds and the implementation of federal programs such as PURPA.

PURPA does not need to be changed. Rather, any industry negatively affected by state utility commission rulings, whether that be small power producers or utilities, must try to educate regulators about its particular concerns. The solar industry clearly has less resources than the utilities, but we are willing to abide by the process--as should everyone else.

Utilities and Public Policy Considerations. Although utilities are profit-making entities for the most part, they are monopolies. Seventy-five percent of the nation's total electricity is produced by 219 private companies. The remaining twenty-five percent of the electricity is produced by 2,190 municipalities, 930 rural cooperatives, 54 joint action agencies and 12 federal power agencies.

PURPA opened utility generation to competition, just as our nation opened the phone lines for competition. Because competition is the American way to provide lower consumer prices, PURPA opened the electric grid to competition. This competition is healthy. Now utilities must show the consumer and the state utility commission that they can indeed produce power as well, and as cheaply, as a small power producer. The avoided cost concept limits the small power producer to producing power for no more than the utility could produce it from a new power plant. The utility is protected by having only to buy power from small power producers who meet the price guidelines, and only when the utility needs capacity.

PURPA is the best way to insure competition while providing the lowest prices for consumers. Although there are some aberrations at the state level, these are isolated occurrences that should not be interpreted as flaws in the original legislation.

CONCLUSION.

Our nation needs to move from finite resources to renewable resources with a clear bias towards domestic energy sources. Whether its imported petroleum or electricity wheeled from Canada, the fact is that American security and a favorable trade balance relies on these principles.

While the United States has developed a broad range of federal incentives to promote solar energy from basic research and development, loans and loan guarantees, tax incentives and export assistance; access to our nation's utility grid is essential for the solar thermal power and photovoltaic industries.

Our industrial competitors including Germany, Japan and others have their own incentives to promote the domestic utilization of solar technologies, some of which are far more aggressive than our own. In addition, a mix of resources are essential for the security and health of our electric energy production industries and the consumer.

The Public Utilities Regulatory Policies Act (PURPA) provides the essential ingredients for effective utilization of solar energy. The requirement of interconnection, tied to the fair and reasonable rate as implemented through the concept of avoided costs, has been useful and necessary for solar projects. Weakening or elimination of these provisions would truly impede solar projects. Utilities make more money from capital intensive plants and through wheeling relationships among themselves even though it may not translate into actual rate savings by consumers. Smaller developing industries like the solar industry do not have the where-with-all to compete on equal footing with utilities. PURPA provides the solar industry with grid access, without the detrimental effects many utilities have claimed.

The federal legislation of PURPA need not be changed. The problems of state interpretation may sometimes seem unwise. However, the occasional problems of PURPA implementation are no more frequent than problems in any other state implemented federal law. SEIA urges you to retain PURPA in its present form.

The CHAIRMAN. Thank you, very much.

Senator Evans.

Senator EVANS. Mr. Chairman, I have listened to enthusiasm almost unbridled for PURPA, which unfortunately sounds an awful lot to me that we have a good deal and we want to protect it. Maybe an unusually good deal that we want to protect.

Usually, when you hear testimony, when there are arguments on both sides about its validity, you think maybe it is balanced, but I didn't hear that. Maybe it is unbalanced; I am not sure.

Mr. Morris, I thought I heard you say and I am not quite sure if I understood correctly—with the Supreme Court decision, no legislation would be effective. Is that really what you meant? That no further legislation could be passed or could be effective because of the Supreme Court decision?

Mr. MORRIS. That certainly was not my intent. The point that I was attempting to make was that the Supreme Court found that by placing the responsibility for putting the pricing of avoided costs in the local control of the PUC's, that the legislation could stand as it was written. What I was suggesting was that if some attempt was made to modify PURPA so that that control was removed from the State level, that it would seem to run counter to that Supreme Court decision.

Senator EVANS. All we have to do is whatever is constitutional?

Mr. MORRIS. That is right.

Senator EVANS. It is constitutional to repeal PURPA; is it not? I am not suggesting that that is a good idea, but that would be constitutional in your view?

Mr. MORRIS. If the Supreme Court had ruled, and I am not sure that I understand your question——

Senator EVANS. We passed PURPA and it has been declared constitutional, presumably we can repeal it.

Mr. MORRIS. Oh, yes. I am not arguing that the Congress could not repeal it. What I am arguing is that Congress should not, in light of that Supreme Court decision, modify PURPA so that it removed the local control as far as the State PUC's are concerned. I think that was in order because, as we have seen demonstrated here today, the conditions are not the same throughout the country, and by placing the control of such things as avoided costs in the hands of the local commissions, they can react to meet the local problems.

Senator EVANS. I understand that. That is the constitutional question, but it still would not prevent Congress, presumably, if they chose to do so, from changing the definition of avoided costs or establishing a different standard, other than avoided costs, or changing any or all of the rules and regulations that apply to PURPA and then still leave it to local control to carry it out.

Mr. MORRIS. Congress giveth; Congress can taketh away.

Senator EVANS. Until they get unconstitutional about it.

Mr. Nicholson, in a cogeneration project—take the wood process industry as an example—I think there has been testimony before, and I am not sure that you would agree that this is true, but testimony that would indicate that a long-term contract for cogeneration may have a higher return at the beginning and a lower return at the end of a long-term contract, especially if it is on some kind of a levelized or fixed contract.

If that is true, how does the utility ensure the reliability over a long term of that power? What happens if the mill decides to go out of business after 20 years of a 35-year power contract?

Mr. NICHOLSON. The best example I can share with you, Senator, is the contract that we negotiated in 1982 with Washington Water Power Co., and since then have been attempting to get approved by the Washington and Idaho Commissions.

In that contract, we are required, as a corporation, to be able to pay back the amount of money during the period in which the levelized payments perhaps were higher if we were to cease generating.

The assurance that is given in there is that if the size of our corporation falls below a certain amount, that we have to obtain a financial obligation, independent, to assure that that money is available.

Senator EVANS. That is fine for a big corporation. How about a small supplier of cogeneration projects; small group, for instance, whether it is using waste wood or whether it is a small hydro developer who doesn't have an enormous amount of financial backing or capacity? How are they going to ensure that that power will continue for the length of the contract?

If there are others who may be more familiar with the question—it doesn't necessarily——

Mr. NICHOLSON. Let me offer this thought: The important thing, from a ratepayer standpoint, is that you want to assure what you are asking about. Even a small unit can obtain those kinds of financial obligations on a bonding basis.

The other thing is that if the units' variable operating costs are lower than the energy-based costs that they are going to get paid, they are likely to be there anyway. So there are a number of ways of going about this, and I strongly believe that the utilities in negotiating those contracts, should address that.

I think there are others who would like to address that, also.

Dr. HAMRIN. I think that the issue, one, that these are businesses, and that they respond to the payments that they get. That is the only way that they earn money.

If avoided costs drop down to such a low rate that the facility could no longer generate and make money, then they might cease to generate. However, if the rate was that low, one would assume that there was very little need for power. That is how avoided costs are supposed to be measured.

It is much more difficult to guarantee that a utility powerplant, such as Rancho Seco nuclear facility in Sacramento is going to be there for its 45 years, which is the length of time its costs will amortize, and in fact, it may never be fired up again, and in fact, the ratepayers will pay all of that and there will be no way to recover the difference if, in fact, that plant only operated 13 years instead of 45 years.

The likelihood or the probability of 20 or 100 small power facilities all ceasing to generate and all going off line at the same time is so low as to almost be nonexistent. So you really have diversified your risks much more than one would have with the traditional utility operation.

Mr. **LYONS**. Senator, if I might add to those remarks. From Ultra Systems point of view, it seems to me that the issue is not how large the company is that has developed the project, but the project itself, and your question seems to rest on two other issues. One is the ability to continue to produce power over time, and the other is the incentive.

I would just like to repeat that waste wood-fired powerplants have tremendous capacity value in that they are long-lived equipment, proven technology and there is little question about the continued availability of waste wood. So that they will be able to continue to produce.

As to incentive, I think this ties into the remark that Dr. Hamrin made; that if utilities need long-term power, then it behooves the utilities to enter into long-term contracts and provide fair long-term avoided costs prices that the operator of the plant can analyze in advance and determine whether or not it wants to enter into a long-term, legally binding commitment.

It is the contract that provides that security.

If, on the other hand, the utilities' needs are for short-term power, and is not concerned about a long-term commitment, then it may want to encourage the developer to enter into only a short-term spot-base contract and, there, again, the marketplace works. The price goes down, it signals a lack of need for power.

Senator **EVANS**. The long-term contract, then, as a utility I would not want to sign any kind of a contract that would have front end-loaded return to the generator. Is that true?

Mr. **BROWN**. In the recent proceeding in Utah, the State Energy Office surveyed the other States regarding the existence of levelized contracts, that is, contracts that are legally binding at the time the obligation is signed for rates. Twenty three States responded, indicating that they had levelized contracts in some form, and only 11 of those stipulated any form of security requirement. They felt the installations were fairly reliable and credible, including among them, of course, the earliest in the group, New Hampshire, which is a typical model, where the second lien on the property asset of the powerplant is acceptable to the utility for the security necessary.

Dr. **HAMRIN**. I think, again, one has to compare the alternatives, and the alternatives are traditional utility powerplants and traditional utility rate recovery, which is not levelized, but heavily front-loaded; that the traditional revenue requirements for utility-built powerplants recovers the cost of that powerplant, frequently 90 to 95 percent is recovered within the first 5 years.

There is no qualifying facility contract anywhere in the country that is anything like that. At most, it is levelized, and frequently only for capacity, not energy, as well.

We did have a levelized contract for energy in California, but because of the security provisions, it was only taken by a relative handfull of qualifying facilities.

Senator **EVANS**. Let me turn, Dr. Hamrin, you used the analogy earlier in your testimony of the downhill racer, and just learning to fall a lot. Unfortunately, you are talking to a skier, and I watch a lot of downhill races and been in a couple. Lots of experts crash, too. They don't quit crashing because they are experts.

Fundamental question: In terms of avoided costs, if a utility foresees no need for additional power for really as far ahead as they can look, isn't their avoided cost zero?

Dr. HAMRIN. No, but it will approach zero. The economic theory will indicate that there is still some use, that they can offset the utility's present generation at less than what it is presently costing them. But the price will be so low that you won't have anyone in business building powerplants to sell to them because it won't be economic.

Senator EVANS. Have there not been truly cases where, in fact a good number of cases, where these plants have been built and foisted off on utilities at avoided costs that clearly turned out to be way beyond any alternative for the utility?

Dr. HAMRIN. As I mentioned earlier, one of the misconceptions is in comparing long term and short term, and I have heard allegations of that sort, when in fact it was strictly a matter of looking at long-term contracts where there was a need for power, that once the qualifying facility filled that need, the new calculation showed there was no longer a need, but that didn't make the previous contract invalid.

I think there has also certainly been regulatory lag. This always happens. Going back to our skier, when you are first learning to ski, sometimes the most expedient way to stop when you are going too fast is to fall down.

We did that in California a bit. Our public utilities commission was just learning and decided it was easiest just to fall down. They have now learned some more professional types of maneuvers, and so we are going into a contracting mode where the contracts have specific megawatts requirements; when those are filled, new calculations are made. There is a methodology for adjusting for the capacity needs of the utilities which will be constantly done on a regular basis so that we do keep up, through time, with the needs of the utility.

I don't think there has been any instance where there has been such a gross problem of either time lag or contracting that the ratepayers have been permanently damaged in such a way that one would want to drastically change that.

Senator EVANS. You would say that the instance of a cogenerator or PURPA generator pushing power onto a utility where it was at a cost in excess of what the utility really needed has only been rare? Has it been modest, has it been common, has it been most of the time during the experience you have had with PURPA all over the country?

Dr. HAMRIN. I think it has been very rare. The numbers that the public utility commission, public service commission look at are provided by the utility. When you say what is the avoided cost, the electric utility is the one who comes in and say—here is our needs or lack of needs for power; here is what it costs us to generate, and so forth.

Most all of the time, everyone else is left in a reactive position of showing—somehow disproving those numbers that are provided by the electric utility, and are coming in with some other set that has some validity in the adjudicatory process and is able to be shown through cross-examination and extensive evidence to be more valid than the utility's.

That is a very heavy burden of proof. I think it is seldom that in any regulatory commission, that intervenors are able to provide such things.

Let me give you a couple of examples of numbers in California, because we heard some numbers earlier from the utilities, and I don't want a complete misunderstanding of avoided costs.

At Pacific Gas & Electric Co., their current average retail rate that they charge retail customers is 8.67 cents. Their current average avoided cost rate, including fixed price contracts and others, is 5.15 cents. They buy for 5; they sell for 8½.

Southern California Edison, their current average retail rate——

Senator **Evans**. Now, wait just a minute. They sell for 8½. That 8½ is based on the cost of generation of power that they are now paying for.

Dr. **Hamrin**. Right; however, Diablo is not yet in there.

Senator **Evans**. Interest rates of a few years ago, which were twice as high, or close to twice as high as they are today.

Dr. **Hamrin**. That is correct, but avoided cost is still significantly below that average retail rate.

Senator **Evans**. Yes; but you say that, you make that statement as if it were somehow pejorative. It is just a fact that cycles go up and down. Interest rates might be 20 percent 5 years from now, too. And that will make avoided costs very much different for them, as well as for everybody else, than it is today.

Dr. **Hamrin**. But I think it still is a good deal for the ratepayers of that utility, and they are paying significantly less than they would have in most of any of the other options the utility has had up to this point.

Mr. **Nicholson**. Senator, there is another piece of evidence addressed in your question, and that is in many parts of the country—I think the Middle South and others, where there is considerable capacity, and the general capacity is either coal or nuclear. The potential avoided costs which are based on the avoided running costs, are so long that there has not been much PURPA based cogeneration brought in to sell power to the utilities.

The areas where you have seen large amounts of power have been where there have been generally high rates, need for capacity, high cost fuel, such as gas and oil. In the areas where there has been large quantities of generation that is coal and nuclear, low-running costs, there has not been much PURPA-generated power.

Senator **Evans**. Let me turn to Mr. Brown, then. You mentioned in your testimony—you have a list there of, admittedly limited reporting, but of small hydro projects, and Washington State happens to lead the list, in terms of, at least, the number of megawatts produced. Yet we are an area that is neither capacity constrained, nor has for the most part any cost at all of fuel.

How come we have so many projects in that kind of a circumstance?

Mr. **Brown**. I think the general circumstance of the opportunity at existing sites clearly was created by PURPA and other regulations that followed.

I think in an excess capacity situation, it may be suitable to make a couple of comments. I think that you will find the small power development helps mitigate against future excess capacity for some of the following reasons, and I will just mention a couple quickly.

Disbursed power product provides the opportunity to reduce the risk to ratepayers and utilities, that is the uncertainties attendant with the construction programs and the purchase programs they are embarked upon which are based on inaccurate forecasting models. And, as we have heard mentioned earlier, the growth rates of the 1970's were used to project some of the commitments that we are now dealing with.

We are now dealing with lower growth rates. We can avoid overbuilding, in effect.

A second general point is that disbursed power production allows for risk shifting back to site owners of the QF's and away from the utility, which is happening in that situation. The business risk is going to the utility customer, the site owner, away from the ratepayer and the shareholder.

I think perhaps, and this may not speak to your situation, but the rate shock that was incumbent in your State and other States from nuclear plant and other arrangements, if the avoided cost is properly set, you can help cope with those circumstances with these kinds of plants over time. I can't address the specifics of why individual plants came on line sooner or later in your State over other States, because I am just not familiar with it, personally.

Senator EVANS. Thank you, Mr. Chairman. I will have some written further questions.

The CHAIRMAN. I think various members of the committee may have written questions to submit to the several witnesses this morning for response in writing. I will appreciate your relatively prompt response to those questions so they may be included in the record.

The record will remain open for additional comments for a period of 2 weeks.

Mr. Nicholson, I have just one question, because you made a comment which I think perhaps needs to be put into a context. You defended the simultaneous purchase and sale as being to the benefit of the ratepayer.

Is that a qualified statement or an unqualified statement?

Mr. NICHOLSON. I know of no instant where I would want to qualify the statement.

The CHAIRMAN. Could I ask one question, hypothetical, then? Let us assume some person comes in with a pumped storage proposal. They are going to pump water up the hill at the typical industrial rate, and then will sell back at avoided cost.

Mr. NICHOLSON. Sir, the case that you are describing is not simultaneous purchase and sale, as I understand that.

The CHAIRMAN. You would not——

Mr. NICHOLSON. Let me explain why that is not the case. They are using electricity to make electricity. The simultaneous purchase and sale that I am describing is an entity generating power, selling, and then buying the electricity needs for its plant to drive pumps, and so on.

The CHAIRMAN. And you defended the simultaneous purchase and sale on the basis that it is a good deal for the ratepayer?

Mr. NICHOLSON. Yes, sir.

The CHAIRMAN. And that is based on the overall benefit to the ratepayer of the generalized benefits coming from cogeneration. Is that correct?

Mr. NICHOLSON. Beneficial to the ratepayer not to have people drop off the system. The industrial plants. The alternative to simultaneous purchase and sale, when the retail rates are high enough, is to serve one's self. In those circumstances, the entity drops off of the system and the other ratepayers on the system pick up the cost.

The CHAIRMAN. Would you be satisfied to have that determination made on a case-by-case basis?

Mr. NICHOLSON. I see no advantage in that to the ratepayer, sir.

The CHAIRMAN. Well, if there was an advantage to the ratepayer, presumably the commission would find there was an advantage to the ratepayer. If, upon analysis, they found there was no advantage to ratepayers, they would find there was no advantage to ratepayers.

Mr. NICHOLSON. Fair point.

The CHAIRMAN. Well, would you object to the proposition that they could do so on a case-by-case basis?

Mr. NICHOLSON. I think if someone wanted to generically address that point, that would be a proper thing to do if it was questioned. I think there is well established validity of simultaneous purchase and sale.

The CHAIRMAN. Thank you all very much for your testimony. I appreciate it.

[Whereupon, at 12:40 p.m., the hearing was recessed, to reconvene Thursday, June 5, 1986.]

IMPLEMENTATION OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

THURSDAY, JUNE 5, 1986

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The committee met, pursuant to notice, at 10:15 a.m., in room SD-366, Dirksen Senate Office Building, Hon. James A. McClure (chairman) presiding.

Present: Senators McClure, Hecht, and Evans.

Also present: E. David Doane, senior counsel; Richard D. Grundy, senior professional staff member; and William B. Conway, counsel for the minority.

OPENING STATEMENT OF HON. JAMES A. McCLURE, A U.S. SENATOR FROM THE STATE OF IDAHO

The CHAIRMAN. The committee will come to order.

Today's hearing is the second session in the committee's 2-day oversight hearing on the implementation of the provisions in PURPA relating to cogeneration and small power production. On the first day of the hearing, testimony was presented by two panels of witnesses, the first representing buyers of power from qualifying facilities, and the second consisting of different types of sellers.

Not surprisingly, the two panels disagreed on a number of specific issues. For example, one issue is whether electric utility ratepayers should receive an immediate economic benefit from the way the States implement the full avoided cost rule.

Another issue is whether State regulators are requiring cogenerators and small power producers to pay adequate compensation to utilities for the costs of providing backup power and making the system modifications necessary for receiving power from qualifying facilities.

A third issue is the question of whether long-term contracts for the sale of QF power to utilities should be subject to periodic renegotiation and possible revision, particularly those requiring levelized payments for the life of the contract.

As a final example, another point of disagreement is the current restriction on utility ownership of qualifying facilities. The utilities contend that they should be permitted to participate more fully in QF projects, now that cogeneration and small power production are no longer infant industries.

There was also general agreement between the two panels on several points. There was a consensus that in many respects, PURPA has worked well, but its implementation by FERC and the States has been far from perfect. Thus, there are numerous complaints from buyers and sellers of QF power, but more from the buyers. These complaints are derived, in part, from the fact that State-level implementation of PURPA has been uneven, ranging from aggressive promotion to virtually no action.

Having identified a number of problems, the witnesses generally recommended that any improvements should be made by FERC and the State commissions, rather than the Congress. For example, there was agreement on the need for a new analysis of FERC's thermal efficiency standards for gas-fired cogenerators. The purpose would be to prevent the payment of high PURPA rates for cogenerated power that does not achieve significant energy conservation.

This morning, the first panel will provide us with the regulators, perspective on how PURPA is being implemented. The second panel will discuss the environmental impacts of small hydrodevelopment. The final panel will address PURPA issues from the viewpoint of industrial consumers of electric power, and in the broader context of our national energy policy.

I welcome the members of the panel. I apologize for being somewhat late, but as many of you may have known, the President decided that he ought to have Members of the Senate down for breakfast this morning. When the President makes that suggestion, most of us listen.

I do want to welcome an old friend with whom I served in the Idaho State Legislature many years ago, Perry Swisher. Perry, it is nice to have you here as a member of the panel.

With that, I will turn to the panel. Your full statements will, of course, be made a part of the record, in full. You will be invited to summarize the high points in whatever way you would like to do.

We will lead off with Mr. Anderson.

STATEMENT OF LAWRENCE R. ANDERSON, DIRECTOR, OFFICE OF ELECTRIC POWER REGULATION, FEDERAL ENERGY REGULATORY COMMISSION

Mr. ANDERSON. Thank you, Mr. Chairman, for this opportunity to testify before this committee, as you begin your oversight hearings on implementation of PURPA.

My name is Larry Anderson. I am the Director of the Office of Electric Power Regulation, at the Federal Energy Regulatory Commission.

The Commission is responsible for the issuance and administration of rules implementing the cogeneration and small power production facility provisions of sections 201 and 210 of PURPA. The primary role of my office in this regard is the processing of several hundred applications each year for certification as a qualifying facility received by the Commission each year.

In addition, we assist the Commission with technical and policy advice in noncertification matters, such as petitions for declaratory orders, requests for rulemakings and requests for waivers of the regulations.

As the tables contained in my prepared testimony indicate, the number of requests for certification of qualifying facilities, status and notices of self-qualifications has increased significantly with each year since the Commission's regulations were promulgated in 1980.

Approximately 63 percent of these filings are for small power production facilities. However, 70 percent of the filed capacity is from cogeneration facilities.

My prepared testimony concerns the three topics specified in the chairman's letter requesting testimony. In each of these areas, I have endeavored to summarize the content of the Commission's relevant rule, the rationale on which the rule was based, and the experience of the Commission in implementing the rule.

With respect to the price paid by utilities for qualifying facility power, the Commission's avoided cost rules give substantial flexibility to the State commissions in nonregulated utilities, which have the primary responsibility for pricing.

With respect to the effects of qualifying facility purchases on utility operations and reliability, the Commission recognized that there is a relationship between the reliability of the qualifying facility, and the price a utility should pay for its electricity and in operating, safety and reliability standards, technical determinations.

Thus, the Commission's rules authorize State commissions of nonregulated utilities to establish standards for system safety and reliability, a task for which they are better equipped than the Commission.

Finally, with respect to the environmental consequences of hydroelectric qualifying facilities, the Commission continues to believe that these consequences are best considered in the context of license and exemption proceedings under part 1 of the Federal Power Act.

That concludes my remarks, sir.

[The prepared statement of Mr. Anderson follows:]

Statement Submitted to the
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
by
Lawrence R. Anderson, Director
Office of Electric Power Regulation
FEDERAL ENERGY REGULATORY COMMISSION
June 5, 1986

MR. CHAIRMAN AND MEMBERS OF THE COMMITTEE:

I am pleased to appear before this Committee as you begin your oversight hearing on implementation of the Public Regulatory Policies Act of 1978 (PURPA). I am the Director of the Office of Electric Power Regulation of the Federal Energy Regulatory Commission. The Commission is responsible for the issuance and administration of rules implementing the cogeneration and small power production provisions of sections 201 and 210 of the PURPA. My office participated in the development of the rules, issued in early 1980, and now serves as the Commission's primary office for processing qualifying facility filings and other electric filings related to qualifying facilities.

Since the Commission's rules were issued, approximately 2700 facilities, proposed and existing, have filed requests for Commission certification as qualifying cogeneration or small power production facilities or notices of self-qualification. These filings, cumulative through March 31, 1986, are summarized in the following tables.

TABLE 1

Qualifying Facility Filings with the Federal Energy Regulatory Commission as of March 31, 1986

Fiscal Year	Proposed Facilities No.	Proposed Facilities MW	Existing Facilities No.	Existing Facilities MW	Total Facilities No.	Total Facilities MW
1980	16	292	13	412	29	704
1981	59	1,207	9	112	68	1,319
1982	186	2,795	22	1,449	208	4,244
1983	394	4,740	28	947	422	5,687
1984	450	5,267	29	621	479	5,888
1985	676	10,496	32	770	708	11,266
1986 (Part)	585	9,921	12	300	597	10,221
Totals	2,366	34,718	145	4,611	2,511	39,329

(Related information on a state-by-state basis is provided in Appendix A.)

It is clear from Table 1 that the number of filings has grown substantially each year. How long this trend will continue is not certain. Also, while the data indicate that qualifying facility activity has increased, Table I does not indicate the actual amount of qualifying facility capacity that is constructed and operated. Many projects for which a filing is made are not constructed. This may be due to one or more of several factors, such as difficulty raising capital, inability to conclude satisfactory power sales contracts with a utility, State or Federal environmental, permitting, or other regulations, interconnection problems, and others.

TABLE 2

Cogeneration Summary by Fuel Type

Data as of March 31, 1986

Fuel	No. Facilities	Capacity MW
Coal	106	5,309
Natural Gas	613	16,211
Biomass	114	2,491
Waste	27	1,760
Fuel Oil	38	559
Other	20	960
Totals	918	27,290

TABLE 3

Small Power Production Summary by Energy Source

Data as of March 31, 1986

Energy Source	No. Facilities	Capacity MW
Water (Hydropower)	541	2,889
Wind	571	1,578
Biomass*	336	4,108
Waste	57	1,216
Geothermal	53	1,914
Solar	30	229
Other	5	107
Totals	1,593	12,040

*Includes municipal waste, landfill gas and sewage treatment plant gas, as well as agricultural and food processing residues.

Tables 2 and 3, while good indicators of the relative proportions of capacity by primary energy source, also do not indicate the amount of capacity actually under construction or constructed and operating. Also, in Table 3, the hydropower figures may overstate the number of projects because different developers competing for a particular site may make separate filings for that site.

In an effort to get better data on how well the goal of PURPA to encourage cogeneration and small power production is being met, the Commission is presently conducting a comprehensive survey of the construction and operational status of the facilities which have filed with the Commission. The survey is in the form of a questionnaire to each of these entities, with provision for follow-up contacts, to resolve any problems of unclear data. The survey is expected to be completed within the next five or six months. However, some preliminary data is available, which suggests that between one half and two thirds of the aggregate filed capacity may be constructed and operated.

The balance of my testimony today addresses the three specific topics identified in Chairman McClure's letter requesting Commission testimony, from the perspective of implementation by the Federal Energy Regulatory Commission. For each, I will attempt to summarize the content of the relevant rule, the rationale used by the Commission in establishing the rule, and the experience of the Commission in administering the rule.

It should be remembered that the PURPA cogeneration and small power production legislation was novel, because of its impact on the relation between utilities and non-utility power generators, and because it assigned major implementation roles to the State regulatory authorities and non-regulated utilities (primarily municipal and cooperative utilities). During the rulemaking proceedings, comments were received from a wide variety of sources, and many of the commenters' proposals were adopted. Thus, the rules reflect the experience and thoughts of all interested parties. The legality of the full avoided cost and interconnection provisions of the rules has been sustained by the Supreme Court in American Paper Institute v. American Electric Power Corp., et al., 461 U.S. 402 (1983).

PRICES PAID BY UTILITIES FOR QUALIFYING FACILITY POWER

Section 210(b) of PURPA requires the rates for purchases of qualifying facility power by electric utilities to be just and reasonable to the electric consumers of the electric utility, in the public interest, not discriminatory against qualifying facilities, and not in excess of the incremental cost to the utility of alternative electric energy ("avoided cost"). The Commission's rules implementing section 210(b) are intended to provide maximum encouragement of cogeneration and small power production, consistent with the specific mandate of section 210(a) of PURPA. These rules are found at 18 C.F.R. Part 292.

Maximum encouragement with respect to purchase rates rests on the flexible nature of the Commission's rules. First, utilities and qualifying facilities are free to negotiate any purchase rate that is mutually agreeable, without reference to avoided cost. Second, if the parties are unable to negotiate a purchase rate, the utility is required to offer to purchase the qualifying facility's electricity at the utility's full avoided cost of avoided energy and/or capacity. Third, the Commission has not imposed a rigid formula for the calculation of avoided costs. Rather, in recognition of the facts that the principle of avoided cost pricing is not one easily translated from theory to practice, and that determinations frequently depend on characteristics unique to particular utilities, the Commission's rules provide for the State commissions and non-regulated utilities to make avoided cost determinations.

The Commission's regulations set forth several criteria which these entities should take into account in making avoided cost calculations, including the availability of the facility's energy or capacity during peak periods, the ability of the utility to dispatch the facility, the facility's reliability, the usefulness of the power during system emergencies, and the aggregate value of qualifying power to the utility's system. However, the rules also afford these entities considerable flexibility, which is consistent with the principle that these entities are primarily responsible for day-to-day implementation of the cogeneration and small power production program. Finally, State commissions and non-regulated utilities may apply to the

Commission for waiver of the avoided cost rule, which may be granted if the applicant demonstrates that full avoided cost is not necessary to encourage cogeneration and small power production.

The Commission does not have available to it data regarding the percentage of power sale contracts that contain negotiated rates or the relationship of such rates to avoided cost rates. If such data are maintained, it would be by State Commissions or utilities. However, it is my impression that many long-term contracts have been executed which provide for rates less than full avoided cost.

Likewise with respect to avoided cost determinations, the Commission does not have data as to actual prices determined by State commissions and non-regulated utilities. State commissions and non-regulated utilities have adopted a variety of methods for determining avoided cost purchase rates. Some of the regulatory authorities have revised their methods in light of experience, which was anticipated by the Commission when it implemented its rules.

No State commission or non-regulated utility has requested a waiver of the avoided cost rule. This may reflect the flexibility which the rules permit in making avoided cost determinations.

A final point with regard to purchase rates is that the Commission's rules and the implementing rules of State commissions and non-regulated utilities may not, pursuant to section 210(b), provide for purchase rates exceeding avoided costs. However, the Commission order promulgating the avoided cost rule noted that State commissions might, under separate authority of State law, establish rates in excess of avoided cost, to provide further encouragement to qualifying facilities.

EFFECTS OF QUALIFYING FACILITY PURCHASES ON UTILITY OPERATIONS AND RELIABILITY

Section 210(a) of PURPA requires the Commission's rules and the State commission and non-regulated electric utility regulations implementing them to include rules respecting minimum reliability of qualifying facilities (including reliability during emergencies) and rules respecting reliability of utility service to qualifying facilities during emergencies.

The Commission's rules regarding reliability of qualifying facilities and utility service to them are general in nature. Qualifying facilities are obligated to provide electric power to utilities during system emergencies according to contractual provisions negotiated with the purchasing utility or as ordered under section 202(c) of the Federal Power Act. Pursuant to the Department of Energy Organization Act, section 202(c), which to my knowledge has never been employed in connection with a qualifying facility, authorizes the Department of Energy to order interconnections and power sales during wars or other emergencies.

Qualifying facilities were not required to make all of their generation available to utilities during system emergencies (except to the extent that section 202(c) of the Federal Power Act may apply) because such a requirement might interfere with industrial processes with resulting damage to equipment and manufactured goods. Many industries install their own generating equipment to avoid just such a result. Thus, to require such facilities to make their generation available to utilities during utility system emergencies rather than permit them to serve their internal needs first might discourage rather than encourage interconnected operation.

The regulations allow flexibility in the application of reliability and safety considerations by State commissions and non-regulated utilities. The preamble to the rule identified two reasons for adopting this flexible approach. First, there is a relationship between reliability and price: the less reliable a qualifying facility's generation is, the less value it has to the utility. Consistent with this principle, the rules provide that reliability is one of the factors to be considered in State commission and non-regulated utility avoided cost determinations. Second, the rule reflects the fact that operating safety and reliability standards are technical determinations. This is an area in which State commissions and utilities are better equipped than this Commission. Consequently, the regulations authorize State commissions and non-regulated utilities to establish standards to ensure system safety and reliability. It is my understanding that purchase contracts frequently provide for price reductions if the reliability of the qualifying facility does not attain specified standards.

It is also my understanding that the North American Electric Reliability Council is drafting proposed technical guidelines for the integration of non-utility generating facilities with the bulk electric power supply. Reportedly, the guidelines will call for a continuous communication capability between a facility and the interconnected utility to exchange information on loading, switching, operations, and safety and emergency-related orders, as well as assumption of the facility dispatch control by the utility during emergencies. It is possible that many qualifying facilities would voluntarily agree to inclusion of such provisions in the utility purchase contract.

ENVIRONMENTAL IMPACTS OF CONSTRUCTION AND OPERATION OF HYDROELECTRIC QUALIFYING FACILITIES

During the rulemaking proceedings to implement Title II of PURPA, the Commission prepared an Environmental Assessment (EA) under the National Environmental Policy Act of 1969 (NEPA). In the EA, the Commission anticipated that there would be significant development of hydroelectric qualifying facilities. The Commission also determined that the environmental impacts of such development are generally site-specific or localized, and could best be dealt with on a case-by-case basis, in the context of hydroelectric licensing and exemption proceedings under Part I of the Federal Power Act.

In licensing proceedings, applicants are required by the Commission's regulations to submit substantial amounts of data regarding environmental impacts of proposed projects. An integral part of this process is the applicant's obligation to consult with State, Federal, and local agencies regarding potential project impacts. The data submitted by applicants are evaluated by Commission staff members with expertise in the various areas of environmental analysis. The Commission staff is authorized to require submission of any additional data necessary to properly evaluate the project's environmental impacts. Based on the information submitted, the Commission prepares an EA and, if warranted, an environmental impact statement.

In recognition of the possibility that there may be significant cumulative impacts of multiple project hydroelectric development in some areas, the Commission approved the implementation of the Cluster Impact Assessment Procedure (CIAP) for three river basins: the Snohomish (WA), Owens (CA), and Salmon (ID). In a CIAP, the Commission reviews pending license applications in the selected area together, to determine to what extent there may be cumulative environmental impacts from clustered project development and what mitigation measures may be appropriate. The three CIAPs established to this point are in various procedural phases.

Based on the data compiled by the above-mentioned procedures (case-by-case or in a cumulative context), the Commission determines whether a proposed project can be made environmentally acceptable by mitigation measures. If so, and assuming all non-environmental standards can be met, a license is issued subject to whatever mitigation measures are found to be necessary. If the Commission finds that a project would, even with mitigation measures, cause unacceptable adverse environmental impacts, the license application will be denied.

Exemptions are handled somewhat differently, but with comparable results. The Federal Power Act and PURPA give the United States Fish and Wildlife Service and comparable State agencies the power to impose mandatory conditions on exemptions to protect fish and wildlife resources. These agencies are authorized to consider the individual and cumulative environmental impacts on these resources of exemptions. Pursuant to their analyses, these agencies develop mitigation measures which are included as mandatory conditions to the exemption. If these agencies determine that the environmental effects of a project would, even with mitigation conditions, create unacceptable impacts, then the Commission will deny the application for exemption.

The Commission has recently considered and denied a request that it amend its regulations to the extent that they permit qualifying facility status for hydroelectric projects. A coalition of environmental groups requested an amendment to the regulations that would foreclose qualifying status whenever a project would adversely affect a waterway found by a Federal or State agency to have important natural, scenic, cultural, or recreational values. Alternatively, they requested that qualifying status not be permitted for any new hydroelectric projects. The petitioners also requested that the Commission conduct a new programmatic environmental review of its PURPA regulations to the extent they permit hydroelectric facilities to have qualifying status. They contended that environmental review of projects in license or exemption proceedings, whether on a case-by-case basis or in a CIAP, is not adequate.

The Commission concluded that the petitioners had not shown that a new programmatic environmental review was warranted at this time, and that the Commission's existing approach to consideration of environmental implications of hydroelectric qualifying facilities was preferable to the petitioners' proposed alternatives. The petitioners have sought judicial review of this decision in Sierra Club, et al. v. FERC, 9th Cir. No. 86-7152 (petition for review filed March 17, 1986).

Thank you again for this opportunity to testify. I will be pleased to answer questions you may have or, if I am not able to do so, will arrange to have answers submitted for the record.

Appendix A

Qualifying Facility Filings with the Federal Energy Regulatory Commission as of March 31, 1986 by State

State	Cogeneration		Small Power Production		State Summary	
	No.	Capacity MW	No.	Capacity MW	Number of Facilities	Capacity MW
Alaska	1	25.0	4	20.1	5	45.1
Alabama	5	335.6	13	130.2	18	465.8
Arkansas	4	29.3	5	7.3	9	36.6
Arizona	2	4.6	4	39.7	6	44.3
California	360	7,033.6	475	4,088.6	835	11,122.2
Colorado	14	192.0	20	209.3	34	401.3
Connecticut	7	237.9	6	79.3	13	317.2
District of Columbia	0	0.0	1	0.7	1	0.7
Delaware	2	93.3	2	14.8	4	108.1
Florida	28	811.1	20	464.3	48	1,275.4
Georgia	4	310.6	5	16.3	9	326.9
Guam	0	0.0	1	19.5	1	19.5
Hawaii	6	19.9	23	175.9	29	195.8
Iowa	3	24.6	16	14.9	19	39.5
Idaho	19	218.6	98	491.3	117	709.9
Illinois	18	110.1	13	49.2	31	159.3
Indiana	3	109.8	5	3.1	8	112.9
Kansas	7	50.6	26	0.3	33	50.9
Kentucky	0	0.0	3	83.8	3	83.8
Louisiana	30	1,834.2	7	132.6	37	1,966.8
Massachusetts	17	921.0	24	272.9	41	1,193.9
Maryland	3	159.0	16	148.6	19	307.6
Maine	5	268.9	35	520.9	40	789.8
Michigan	14	270.5	30	198.9	44	469.4
Minnesota	6	150.1	18	33.2	24	183.3
Missouri	4	130.2	3	0.8	7	131.0
Mississippi	9	75.7	3	13.1	12	88.8
Montana	3	50.0	17	41.3	20	91.3
No. Carolina	21	888.4	23	131.7	44	1,020.1
No. Dakota	1	9.0	11	0.2	12	9.2
Nebraska	0	0.0	2	0.3	2	0.3
New Hampshire	11	656.4	46	416.3	57	1,072.7
New Jersey	43	725.9	21	195.6	64	921.5
New Mexico	4	26.9	7	2.1	11	29.0
New York	65	1,246.6	93	759.1	158	2,005.8
Nevada	0	0.0	25	789.4	25	789.4
Ohio	9	158.7	14	238.3	23	396.9
Oklahoma	12	602.2	171	44.3	183	646.5

	Cogeneration		Small Power Production		State Summary	
State	No.	Capacity MW	No.	Capacity MW	Number of Facilities	Capacity MW
Oregon	2	20.0	34	274.3	36	294.3
Pennsylvania	64	1,374.5	55	820.4	119	2,194.9
Puerto Rico	5	48.3	4	14.3	9	62.6
Rhode Island	0	0.0	5	16.4	5	16.4
So. Carolina	4	200.1	9	8.1	13	208.1
So. Dakota	0	0.0	3	3.5	3	3.5
Tennessee	14	63.7	7	23.1	21	86.7
Texas	56	6,785.7	53	280.4	109	7,066.0
Utah	6	135.9	17	49.8	23	186.2
Virginia	18	787.7	30	57.4	48	845.1
Virgin Island	0	0.0	1	30.0	1	30.0
Vermont	2	26.6	21	109.6	23	136.2
Washington	2	29.1	21	116.4	23	145.5
Wisconsin	1	15.0	12	71.4	13	86.4
West Virginia	0	0.0	8	237.3	8	237.3
Wyoming	4	21.6	7	79.4	11	101.0
Total	918	27,289.7	1,593	12,039.6	2,511	39,329.4

The **Chairman**. Thank you, Mr. Anderson.
Perry.

STATEMENT OF PERRY SWISHER, PRESIDENT, IDAHO PUBLIC UTILITIES COMMISSION

Mr. **Swisher**. Mr. Chairman, to summarize my remarks, I spent some time in the prepared remarks discussing the fact that we are in surplus, virtually, all over the country at the moment. It makes it a very difficult time to discuss PURPA because the cogeneration of small hydroindustries are maturing at exactly the wrong time, which is just the way the energy system works. I don't understand it, but that is how it is.

And, because it is that way, the discussion over avoided costs, I think is important. Our experience with the avoided cost formula in Idaho, and ours is one of the first one or two put in place, has been that the price in the long-term contracts has moved down from the mid-60 mils, into about the 45- or 48-mil range, which says that the avoided cost formula is working. That is pretty significant.

It means, too, that the debate over the long-term levelized rates should cool off a little bit, because the new contracts that are written will be at lower rates than they were during the peak of the inflation and capital costs of the baseload plants on the utility system.

If Congress were to do anything to eliminate the qualified facilities access to a levelized rate, that, of course, would be the end of cogeneration, because nobody is going to finance someone trying to build 125-kilowatt plant, dealing with, let's say, a 2,000-megawatt utility. The financial community, with no exception, sees that as an unfinanceable situation.

Although you have a separate panel on environment, as a regulator, I couldn't leave the subject alone, partly because—and I don't know what your rules of protocol and etiquette are, Mr. Chairman, with respect to the other Body, but within the——

The **Chairman**. We give them polite deference.

Mr. **Swisher**. Just be polite? I can do that. I can handle it.

In the dam relicensing legislation in the House, Congressman Wyden of Oregon has proposed to excuse utilities from the purchase of small hydro. Our difficulty with that, in order to be polite, is that most of the United States lies east of the Cascade Range and it doesn't really exist in the way it is perceived in the Portland rose garden.

Stream A is not Stream B. Our experience is that environmental agencies and our constituencies are very vigil in that nothing should be done to shut down our ability in the great basin and in the desert streams to enhance the environment by impoundment, whether it is with small hydro facilities or other kinds of power. And I would caution your committee against any generalizations based on anadromous and applying them to the whole universe of the North American Continent.

That would summarize my remarks.

[The prepared statement of Mr. Swisher follows:]

PURPA - Senate Energy Committee Hearing June 5, 1986

Prepared remarks of Perry Swisher, President of the Idaho Public Utilities Commission. Mr. Swisher is a member of the Electricity and Executive committees of the National Association of Regulatory Commissioners. He was a newspaperman, state legislator and university administrator before entering state regulation in 1979.

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There is a law akin to Parkinson's and Murphy's, and not a statute, that prohibits an enduring balance between electrical ~~and~~ energy capacity and demand.

Thermal co-generation and small hydro financing, design and installation have hit their stride in the Pacific Northwest just when the whole region is in surplus.

Moreover, the Columbia River Basin is in its sixth successive good water year. And next door in California, the triple impacts of the OPEC price collapse, the massive co-generation component of gas-fired Enhanced Oil Recovery in the Bakersfield area, and the coming on-line of the Palo Verde and Diablo Canyon nuclear plants have transformed what had been the Black Hole for British Columbian and Northwest energy surpluses.

We're lucky to get a third of the price we were receiving last year for our exports, and California's Public Utilities Commission meanwhile has extended its 1985 suspension of standard-form PURPA contracts.

-o-

A PURPA review in these circumstances is as difficult as a review of utility base-load plant requirements proved to be in the late 1960's and 1970's. Electricity demand was growing then by 7 per cent per year in most of the far West.

Double-digit inflation and interest rates above 20 per cent humbled the planners of 1,200-megawatt base-load utility plants early in this decade. The epic Washington Public Power Supply System debacle added its billions of dollars of unproductive costs.

By 1979, thermal-plant increments to the cheap hydro rate base had introduced the region to price resistance. Insulation flowed into our attics. Energy conservation became habitual. By last winter wood stoves had become the primary space heater in 20 per cent of the homes served by some of the inland utilities. Pine-scented winter inversions are now the norm in all but our most windswept cities; in January it's like a bad day in Los Angeles, every day. We can see neither the forest nor the trees, but we can breathe their byproduct.

Before these developments, the Pacific Northwest used four times as much electricity per capita as the rest of the nation. In Idaho, where two of our three major utilities are still 65 per cent or more hydroelectric, and despite conservation, we still do. Both of the hydro utilities have household rates well below a nickel per kilowatt hour.

Although the Pacific Northwest Power and Conservation Act passed by Congress in 1980 entitles our investor-owned utilities to sell to householders and pump irrigators at the exchange rates of the federal Bonneville Power Administration, only one of our investor-owned utilities does so, the coal-fired Utah Power & Light Co. The rest of the private utilities' rates are lower than Bonneville's.

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Because PURPA entitles the co-generator and the small hydro developer to rates reflecting the cost of the utility plants that non-utility generation avoids, is there a future for non-utility projects? Is there, that is, in a region in surplus, blessed with hydro, cursed with WPPSS, dumping in a recently unlimited Southwest export market, wedded now to conservation and wood stoves, and facing increasing import competition from Canada?

The answer may be a surprise, but the answer is yes.

Agriculture, mining and timber were hit hard by the deep recession of the early 1980's. None of them has returned to pre-recession vigor. All of them are basic industries in my region. I won't bore you with a list, but timber-, mining- and commodity-based industries that are still running, wouldn't be -- or would be severely curtailed -- if they threw away their combustibles in pre-PURPA fashion, if they did not recycle the heat from manufacturing processes, if they did not design electric generation into rebuilds and new processes.

That is the trend. PURPA was in place during this return to industrial generation. It is my experience and judgment that an avoided-plant methodology for setting levelized rates is still a logical foundation for its future.

Other trends in supply are toward market competition among utilities in surplus, the clustering of co-generators on the Houston model, and unregulated subsidiary or joint-ventures central-plant proposals, which the investment community now prefers to the rate-basing trauma of the regulatory hearing room.

As for small hydro, the combination of snow pack in 11,000-foot mountain ranges with a leisurely return of that moisture to the sea makes the Columbia a "mighty engine." It works on a smaller scale for the canals and creeks of the basin. PURPA revenue from canal drops is helping irrigators pay for the maintenance of ditches and weirs. Every penny counts in the survival budgeting of farmers who raise grain, potatoes,sugar beets and livestock.

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I appreciate, perhaps more than they know, the environmental concerns of those non-Idahoans who don't want small hydro to ruin the anadromous spawning gravels and the fly fishing streams of Idaho. But the havoc imagined in the rose gardens of Portland is not the reality for those whose know-how is three or four generations deep in the watersheds east of the cascade Range.

In much of the Great Basin, rainfall is less than 10 inches a year. There the topsoil is so thin, the ground cover so fragile and the runoff so swift that any impoundment -- whether a turbine head or a fish pond -- is on the average apt to be an enhancement and not degradation. In my lifetime, I have watched the timberline on Idaho's eastern slope creep downward as the water from irrigation and from reservoirs, retained water that otherwise would have gone down to the sea, has moderated a climate that used to crack one's skin with desert dryness by summer's end.

Stream A is not Stream B. It is best not to generalize. We should widen, not Wyden, our understanding of point sources of energy. I do agree with the Oregon congressman that the fate of pristine trout streams, breathtakingly scenic waterfalls and salmon spawning gravels should not depend on rulemaking whims at the Federal Energy Regulatory Commission for an uncertain future under PURPA-alone standards.

But I submit that the environmental-review agencies and their constituencies are vigorous guardians. Your staffs know or can find out whether their interventionary and review powers need further statutory attention. If they require it, do it, but don't shut down the hydro resource of a concrete-lined canal far beyond the last reach of the anadromous runs, for example, because some nerd on the Little Salmon tries to stick a Pelton wheel on the wrong creek.

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Sabotage of central facilities is demonstrably on the agenda of terrorism, so I take some comfort in decentralized energy sources as exemplified by PURPA projects. Other technologies are feeding the decentralizing trend. Consider photovoltaics already in use on one of our utilities, Washington Water Power company, for service without power lines to remote consumption sites. And the now viable fluidized-bed thermal units can be assembled close to a new load, instead of relying on a huge central plant somewhere else. One should resist the invitation to join the Montessori school that insists new central plant will never again be needed because we can all become our own little generators. Resist as well the paternalistic opposite, which says that we will run out of electricity unless we restore the central-plant monopoly that characterized the last seventy years.

Wherever we get the juice and however much we conserve, I can imagine a future only with more, not less, electricity in it. The stuff is magic; its potential is far from developed.

It is not logical to believe that there have been enough lawn clippings and dead fish since Cambrian times to account for all the methane this planet contains and where it is being found. More will be found as soon as its oil-field patrimony is severed by the scientific evidence. But there is no question that the earth's oil reserves are declining; nothing magic can happen to enlarge that finite resource.

OPEC and Saudi Arabian scenarios or their collapse, and the exigencies of earning a return on refinery investment currently in place, will not prevent the return of higher oil prices. When prices go up again, Americans won't give up the mobility and freedom of individualized transportation, any more than an Indian would shoot his horse. People didn't give it up the last time around.

In the next price cycle, or at the very least the one that shortly follows on, automotive transportation will become gradually but then primarily electric. For the sake of Idaho's lead-silver mines I might wish it otherwise, but obviously electric energy can be stored in an element lighter than lead. In fact, it can be stored in the lightest metal of all, lithium, and it will be.

An imaginative manufacturer will take over the commuter market in the classic Volkswagen strategy, as soon as lightweight storage supplies the mileage range, gasoline prices supply the incentive and, perhaps, an act of Congress formalizes the end of vehicular dependence on dinosaur juice.

Efficiently managed, adapting such technologies as semi-conductivity to larger surfaces and circuits, electricity can clear the ice and snow from our Northern streets and sidewalks, serve up Southern comfort under glass on cool, covered avenues using inverse heat exchange, supplant diesel in locomotives, and grow table vegetables in a room next to the table. Things to come, I imagine.

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Single-owner supply of electricity, however, is going out of style. Utilities aren't going out of style. But requiring each utility or even a consortium to maintain a stand-alone vertical capacity for its load has already evaporated, even if most of us weren't looking.

A number of assumptions that underlay the National Energy Act package enacted in the 1970's are no longer valid or weren't then. Energy constraints, sources and configurations are a changing mix. PURPA, a part of that package, concentrated on ending the monopoly approach to electricity price, supply and access to the consumer.

To repeal PURPA or to choke off its contribution to our resources may be possible in this surplus, when the public isn't paying a lot of attention. I think you know that would be a mistake in a time of energy scarcity. It would also be a mistake today.

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If you find situations in which a utility and its ratepayers pay far more over time than they would for central utility plant, write the corrections for FERC and the states to implement. Don't prohibit non-utility generation, directly or indirectly; that would be a sickening surrender.

If you find significant instances of industries designing wasteful energy consumption into their plants or retrofits because cogeneration is the artificial stimulant for their strategems, set thermally based criteria as the disincentives. Don't reverse the economic gains we have made by salvaging wasted energy.

If you conclude that an abundance of co-generation and/or small hydro is disproportionate to the demand in a given utility's service area, then assure access for that resource to markets beyond the service area. Use categorical common-carriage entry to that end -- it can be done without turning a utility's own transmission system into a freeway for everybody else. FERC is rapidly learning how to do that with natural gas, where the pressure from point sources is a thousand times greater.

If you receive evidence that there are speculators in PURPA contracts who have made out like bandits, when compared to a utility's allowed rate of return, remember that found money is a phenomenon in any change you make in market access. Recall the overnight millionaires in uranium mining. PURPA is not that sensational and is a long-haul commitment or should be.

Keep in mind too that my job includes seeing to it that the utility stays alive. In contrast, for every PURPA contract approved, a number of entrepreneurs or perpetual-motion freaks lose their money or time or both. Foil snake-oil salesmen if you can. But don't shut off the non-utility generator's ability to finance. The non-utility developer finds capital only if there is an assured price for the life of a contract. No investor expects a 125-kilowatt seller to survive without it when the customer is a 3,000-megawatt monopsony.

If there proves to be justifiable concern that Qualifying Facility operators can walk away from their obligation to deliver power for the life of a contract, after benefitting from front-end rate loading in the early years, the federal statute could be changed to forfeit the plant itself in that event. I believe the better answer is reserve funds, sinking accounts, or insurance, a more hands-on and utility-specific approach.

Most of the alarums come from senior utility executives who built their careers on being reliable sole providers. Their reactions are what you would expect from the Senate Dining Room if it had been since it opened the only restaurant in the District and Congress suddenly allowed pizza parlors and fern bars and Szechuan restaurants.

The loss of central-plant sovereignty won't bring on the equivalent of ptomaine poisoning, but the pride of these executives is understandable. For decades, utility plants created economies of scale that reduced the cost and enormously expanded the public's use of electricity. The "Power & Light" in the logo of utilities stems from a time when householders bought light bulbs and light and not much else from the companies. If your career had paralleled the revolution in the use of electricity, you would be proud too.

But then plants got so big that construction outran design, record inflation coincided with the industry's construction peak, finite fuels became expensive, and the last big dam sites were gone. Now times have changed again, beyond reversal.

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In PURPA compliance, private utilities are paragons compared to public power. In general, publicly owned utilities ignore PURPA unless we're speaking of a city that wants to burn municipal wastes for cogeneration to cut landfill needs.

For instance, the Bonneville Power Administration, in behalf of all its preference (public) customers, says with a straight face that its avoided cost is the current price of surplus firm hydro. They get away with it because of the statutorily incestuous relationship among Bonneville, FERC and the Department of Energy.

Several qualifying facilities in Idaho, including one wood-burning sawmill and another in Wyoming, are located in publicly-owned utilities' service areas, but sell to the private utilities that Idaho regulates. It may not be fair, but that's how it is under current PURPA enforcement. I know of no single PURPA sale to a municipal or an electric co-op in the Northwest. I'm sure there isn't one in Idaho.

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Finally, I gather that the Committee wants to know if avoided-cost rates are too high and if utilities should be allowed to own more than 50% of a PURPA facility. Because we include the surplus, for as long as it is projected to last, the calculation of avoided cost in Idaho has moved down from a maximum in the mid-60-mills range in the 1981-84 period to about 45 to 48 mills today. This is below the generating costs of new utility plant now coming on line. In that sense, avoided cost is working. Indefinite escalation isn't happening.

There should be no objection to utilities developing co-generation through unregulated subsidiaries, as a few are doing now. The outright majority ownership of PURPA projects by regulated utilities invites mischief and an abuse of monopsony power. Please note that nothing prevents utilities from investing in small-scale projects now, other than their own preoccupation and that of many regulators with traditional big baseload plants.

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I am grateful for the chance to offer these comments. I owe myself something too because I didn't relate horror stories and Horatio Alger stories about Idaho's PURPA battles, which is more fun, but distracting. To close, here are the non-utility generating statistics for Idaho. Thank you.

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APPENDIX

IDAHO COGENERATION & SMALL POWER PRODUCTION
Status Report as of 5-6-86

Interconnect Utility	SIGNED CONTRACTS No. of Projects	KW	ACTUALLY CONNECTED No. of Projects	KW
Idaho Power Co.	47	82,558	42	75,948
Washington Water Power*	9	21,030	4	7,967
Utah Power & Light	13	21,200	8	12,690
Pacific Power & Light	1	250	1	250
Totals	70	125,038	55	96,855

*Does not include Potlatch (36,500 KW) and St. Maries River (3,400 KW)

FUEL OTHER THAN HYDRO

Idaho Power Company	Wood Waste	25,500 KW
	Methane Gas	150 KW
	Elem. Sulphur	12,000 KW
	Total	37,650 KW
Washington Water Power	Wood Waste	6,250 KW
	Wind	17 KW
	Total	6,267 KW
Utah Power & Light	Wind	100 KW

IDAHO COGENERATION & SMALL POWER PRODUCTION STATUS REPORT

Signed Contracts Only as of 06-02-86

	PROJECT NAME	KW	UTILITY	TYPE	COMMENTS	CONTRACT SIGNED	DATE 1ST GENERATED
	IDAHO POWER COMPANY						
1	Deveny, Willis Riggins, Idaho	110	IPCo	Hydro	Shingle Creek Hydro Power	08-25-82	07-15-83
2	Elk Creek N. of New Meadows	2,000	IPCo	Hydro	Elk Creek Sithe Energies, LA, Calif	08-31-84	12-01-85
3	Evergreen Energy Tamarack, Idaho	5,000	IPCo	Wood	Wood Waste	09-16-81	05-16-83
4	Boise Cascade Emmett Sawmill	14,000	IPCo	Wood	Emmett Power Co.	01-12-84	05-30-85
5	Owyhee Dam Power Proj. Owyhee Dam Sub.	5,000	IPCo	Hydro	Owyhee Irrigation Dist. Oregon	04-27-84	08-08-85
6	Birch Creek Trout Co. Hagerman, Idaho	51	IPCo	Hydro	Cliff Jenson	07-01-83	04-29-84
7	Bowler, Aldrich Hagerman, Idaho	70	IPCo	Hydro	Snake River Pottery	07-11-84	11-19-84
8	White Water Ranch Co. Hagerman, Idaho	160	IPCo	Hydro	Sites 1/2/3 Combined	05-16-84	07-11-85
9	City of Hailey Hailey, Idaho	62	IPCo	Hydro	Recovery Turbine	06-24-85	02-17-85
10	Stevenson, Lynn Bliss, Idaho	75	IPCo	Hydro	Plant #1	01-12-84	04-23-84
11	Stevenson, Lynn Bliss, Idaho	65	IPCo	Hydro	Plant #2	01-12-84	07-05-84

* No Certificate

B.P.C. - Bonneville Pacific Corp.

IDAHO COGENERATION & SMALL POWER PRODUCTION STATUS REPORT

Signed Contracts Only as of 06-02-86

	PROJECT NAME	KW	UTILITY	TYPE	COMMENTS	CONTRACT SIGNED	DATE 1ST GENERATED
12	Lemoyne, John Hagerman, Idaho	35	IPCo	Hydro	Output of Fish Hatchery Rt 1, Box 148, Hagerman	06-23-85*	01-01-84
13	Snedigar Ranch Buhl, Idaho	540	IPCo	Hydro	Silo Creek	02-24-84	01-01-85
14	White (Mud Creek) N.W. of Buhl	205	IPCo	Hydro		07-23-85	01-10-86
15	Northside Canal (Y-8) Bliss, Idaho	85	IPCo	Hydro	Ted Diehl 921 N. Lincoln, Jerome	04-20-83	05-19-83
16	Curry Cattle Co. Filer, Idaho	222	IPCo	Hydro	Twin Falls	02-07-83	06-04-83
17	Trout Co. Clear Springs Hagerman, Idaho	238	IPCo	Hydro	On Billingsley Creek	01-07-85	08-01-85
18	Big Wood Canal Co. Gooding, Idaho	139	IPCo	Hydro	Black Canyon #3 112 S. Apple, Shoshone	03-02-84	05-01-84
19	Knight, Jim E. of Gooding	340	IPCo	Hydro	Mutual Energy/Bigwood Canal	06-10-85	09-14-85
20	Cogeneration, Inc. Shoshone, Idaho	382	IPCo	Hydro	Shorock Hydro, Inc. PO Box 1787, Twin Falls	10-13-81	06-21-82
21	Kaster, Richard Buhl, Idaho	356	IPCo	Hydro	Output of Fish Hatchery Rt 3, Buhl	10-07-83	01-01-84
22	Canyon Springs Twin Falls, Idaho	130	IPCo	Hydro	Canyon Springs Golf Course J.D. McCollum	04-12-84	10-20-84
23	S & S Partnership Buhl, Idaho	520	IPCo	Hydro		10-30-81	02-20-82

* No Certificate

B.P.C. - Bonneville Pacific Corp.

IDAHO COGENERATION & SMALL POWER PRODUCTION STATUS REPORT

Signed Contracts Only as of 06-02-86

	PROJECT NAME	KW	UTILITY	TYPE	COMMENTS	CONTRACT SIGNED	DATE 1ST GENERATED
24	Ravenscroft, Vernon Tuttle, Idaho	615	IPCo	Hydro	Malad River	09-02-82	12-15-83
25	Briggs Creek W. of Buhl	600	IPCo	Hydro	Richard Kastor Project Rt 3, Buhl	07-06-84	09-30-85
26	Sagebrush Powerplant E. of Gooding	433	IPCo	Hydro	So. Gooding Main Canal	06-10-85	08-02-85
27	Little Wood E. of Gooding	740	IPCo	Hydro	John Arkoosh 601 Nevada, Gooding	06-24-85	
28	Clear Springs Trout Buhl, Idaho	520	IPCo	Hydro	Output of Fish Hatchery PO Box 712, Buhl	12-16-82	11-02-83
29	Cogeneration, Inc. Twin Falls, Idaho	2,045	IPCo	Hydro	Rock Creek	10-13-81	09-11-83
30	Koyle, John & Margaret Gooding, Idaho	1,250	IPCo	Hydro	Malad River Rt 2, Gooding	02-15-83	01-15-84
31	Kasel & Witherspoon Twin Falls, Idaho	900	IPCo	Hydro	Near Snake River Canyon	06-23-83	02-15-84
32	Lateral #10 Buhl, Idaho	1,600	IPCo	Hydro	Cogeneration, Inc. c/o Stephen Harmsen, 350 S. 400 E., SLC UT 84111	06-08-84	05-03-85
33	Crystal Springs Filer, Idaho	2,441	IPCo	Hydro	PO Box 1892, Twin Falls	03-31-84	11-01-85
34	Pigeon Cove Power Co. Filer, Idaho	1,890	IPCo	Hydro	PO Box 128, Filer	05-11-83	09-30-84
35	Geobon 2 E. of Shoshone	927	IPCo	Hydro		03-01-85	11-30-85

* No Certificate

B.P.C. - Bonneville Pacific Corp.

IDAHO COGENERATION & SMALL POWER PRODUCTION STATUS REPORT
Signed Contracts Only as of 06-02-86

	PROJECT NAME	KW	UTILITY	TYPE	COMMENTS	CONTRACT SIGNED	DATE 1ST GENERATED
36	Littlewood Reservoir N.W. of Carey	2,400	IPCo	Hydro	B.P.C. 200 E.S. Temple, #300, SLC UT 84111 (Rbt. Wood)	07-27-84	10-01-85
37	Rancher's Irrigation S.W. of Jerome	1,200	IPCo Marcos Ranches	Hydro	Northside Irrigation, Inc. Paul Garff, 150 Main St., Gooding, ID 83330	02-28-85	06-01-85
38	Cedar Draw Near Twin Falls	1,550	IPCo	Hydro	Rbt. Wood, B.P.C. 200 E.S. Temple #300, SLC, UT 84111	01-19-84	05-02-84
39	Lowline Canal S. of Hansen	7,970	IPCo	Hydro	Lowline Canal (B.P.C.) 200 E.S. Temple #300, SLC, UT 84111	06-08-84	04-05-85
40	Iorg, Jess American Falls, Idaho	10	IPCo	Wind	Windmill/Induct. Generator	08-12-83	08-26-83
41	Fall Creek - Benson American Falls, Idaho	150	IPCo	Hydro	Fall Creek	05-08-84	
42	Pocatello Wastewater N.W. of Pocatello	150	IPCo	Cogen	Methane Gas Sewage Plant	06-28-85	09-01-85
43	Afton Energy, Inc. Afton, Wyoming	6,500	IPCo	Wood Waste		08-12-82	02-15-84
44	Tunnel #1 Power Proj. Tunnel Canyon	4,800	IPCo	Hydro	Owyhee Irrigation Dist.	06-06-85	
45	Reynolds Irrigation Walters Ferry Bridge S. of Nampa	264	IPCo	Hydro	Sam Pitman Star Rt, Box 55, Melba	07-03-85	12-01-85
46	Mitchell Butte Malheur County, OR	1,675	IPCo	Hydro	Hosey & Associates	06-06-85	01-01-89 est
47	Simplot Pocatello	12,000	IPCo	Cogen	Non-Firm Power Reaction in Sulfuric Acid Process	01-08-86	01-13-86

* No Certificate

B.P.C. - Bonneville Pacific Corp.

IDAHO COGENERATION & SMALL POWER PRODUCTION STATUS REPORT
Signed Contracts Only as of 06-02-86

	PROJECT NAME	KW	UTILITY	TYPE	COMMENTS	CONTRACT SIGNED	DATE 1ST GENERATED
48	Schaffner Hydro	525	IPCo	Hydro		12-20-85	05-15-86
49	Dan D. Hudson	268	IPCo	Hydro	3 Miles W. of Buhl Deep Creek	03-19-86	01-15-87
		83,208					
	WASHINGTON WATER POWER COMPANY						
1	Potlatch Corp. Lewiston, Idaho	36,500 #3	WWP	Cogen	Contract pending renegotiation 60,188 KW Total - 3 turbines		On-Line
2	Woodpower Power Project Plummer, Idaho	6,250	WWP	Cogen		08-19-82	On-Line
3	Elk Creek Falls Project Elk Creek Falls, Elk River	4,500	WWP	Hydro	Hy-Tech Company	12-28-84	10-01-86 est
4	Clearwater Power Project Orofino, Idaho	2,063	WWP	Hydro	Orofino Creek	07-17-85	06-30-88 est
5	Jim Ford Creek Project Near Weippe, Idaho	1,500	WWP	Hydro	Jim Ford Creek	07-17-85	06-30-87 est
6	Big Sheep Creek Northport, Washington	1,500	WWP	Hydro	Big Sheep Creek	10-01-84	12-01-85 est
7	Hecla Power Project Burke, Idaho	500	WWP	Hydro	Star Mine Richard Gresham	05-09-85	01-01-86 est
8	Lucky Friday Project Mullan, Idaho	200	WWP	Hydro	Lucky Friday Mine/Hecla		On-Line

* No Certificate

IDAHO COGENERATION & SMALL POWER PRODUCTION STATUS REPORT
Signed Contracts Only as of 06-02-86

	PROJECT NAME	KW	UTILITY	TYPE	COMMENTS	CONTRACT SIGNED	DATE 1ST GENERATED
9	Ernest Lindquist Moscow, Idaho	17	WWP	Wind			On-Line
10	Panther Creek	4,500	WWP	Hydro	Panther Creek, Skamania, WA	11-18-85	06-30-88
11	St. Maries River Hydro Benewah County	3,400	WWP	Hydro	St. Maries River QF 86-281	11-15-85	
		60,930					
	UTAH POWER & LIGHT COMPANY						
1	Pancheri, Inc. Howe, Idaho	80	UP&L	Hydro		03-01-83	
2	City of Preston Preston, Idaho	400	UP&L	Hydro	Glendale Reservoir	02-24-82	
3	Last Chance Canal Grace, Idaho	1,400	UP&L	Hydro	Bear River	02-24-81	
4	Bonneville Pacific Tetonia, Idaho	5,000	UP&L	Hydro	Teton River	12-04-84	
5	Birch Creek Power Co. Idaho Falls, Idaho	2,800	UP&L	Hydro		08-21-84	
6	Nicholson's Sunny Bar N. of Howe	350	UP&L	Hydro	Rocky Run Creek	06-27-85	
7	D & D Stauffer Howe, Idaho	3,560	UP&L	Hydro	Dry Creek	11-30-84 06-05-85 Amend.	

* No Certificate

B.P.C. - Bonneville Pacific Corp.

IDAHO COGENERATION & SMALL POWER PRODUCTION STATUS REPORT

Signed Contracts Only as of 06-02-86

	PROJECT NAME	KW	UTILITY	TYPE	COMMENTS	CONTRACT SIGNED	DATE 1ST GENERATED
8	Mink Creek Franklin County	2,700	UP&L	Hydro	Robert Fackrell	05-21-85	01-15-86
9	John R. Wheeler	100	UP&L	Wind		02-14-85	
10	Briggs Project Teton River	300	UP&L	Hydro		02-07-85	
11	Georgetown Irrigation Co.	380	UP&L	Hydro		07-02-84	
12	Energenics Systems, Inc.	1,750	UP&L	Hydro		05-07-84	
13	Ingram Warm Springs Ranch	2,380	UP&L	Hydro		03-04-86	
		21,200					

PACIFIC POWER & LIGHT COMPANY

	PROJECT NAME	KW	UTILITY	TYPE	COMMENTS	CONTRACT SIGNED	DATE 1ST GENERATED
1	Jim White Clark Fork, Idaho	250	PP&L	Hydro	Deer Creek 1,300,000 Kwh	09- -81	11- -81

* No Certificate

The **Chairman**. Thank you, very much.

Mr. Gioia.

STATEMENT OF PAUL L. GIOIA, CHAIRMAN, NEW YORK PUBLIC SERVICE COMMISSION

Mr. **Gioia**. Good morning, Mr. Chairman. I am Paul Gioia, chairman of the New York State Public Service Commission.

Since the announcement of PURPA, there has been a significant progress in New York State in the development of alternate forms of energy production—266 on-site generation contracts, approved by the commission, to date total approximately 537 megawatts, an amount approaching the 634-megawatt capacity of the only large central generating station built in New York during that period.

In addition, there are contracts currently pending or in negotiations representing an additional 1,300 megawatts of capacity. This development has come about as a result of the commission's implementation of PURPA and related State legislation, as well as its own initiative to encourage alternate energy production.

It is important to note that this development has occurred in New York during a period when our generating capacity exceeds peak demand by about 40 percent.

The New York State Public Service Commission has established a full avoided cost standard and avoided cost tariffs for all of the State's utilities, and these tariffs are relitigated in the utility rate cases.

The commission has also developed long-run avoided cost numbers for all New York utilities.

First, a settlement agreement was reached with respect to the Niagara Mohawk Co., which granted producers to deliver power at the distribution level at 5.5 cents per kilowatthour in 1985, increasing steadily to 19.6 cents in the year 2000.

This equated to a levelized payment of 7.67 cents per kilowatthour for the 10-year period ending 1994.

The numbers were to be recalculated in 2 years. The commission reserved the right to revise the numbers sooner if there were major changes in the factors affecting the calculation of avoided costs. In fact, primarily because of reduced fuel prices, the commission was petitioned by Niagara Mohawk to review the long-run settlement numbers, and it undertook such a review.

Following the review, the commission adopted a new long-run forecast for Niagara Mohawk, as well as the other major New York utilities. These long-run numbers are substantially lower than the settlement numbers, primarily because of lower fuel cost estimates.

Niagara Mohawk, for example, power delivered at the distribution level, the rate was set at 4.28 cents per kilowatthour in 1986, increasing to 14.6 cents in 2001, which equates to a levelized payment of 5.58 cents for the 10 years ending 1995.

The commission also promulgated standard contract offers, which vary depending upon the type of the facility and size. Hydro facilities were treated more favorably. We granted special treatment to small hydro projects because of the special benefits which we believe they provide.

These include longer useful lives; they are unaffected by fluctuations in fuel prices; they have lower operating costs; are environmental superior to some other alternative; and reduced our reliance upon oil and gas.

Among the options offered, hydro projects had contracts with 15-year long-run estimates, regardless of facility size. They were also offered contracts with levelized, long-run numbers, 15 years, and payments in excess of long-run numbers for facilities which could guarantee power on peak periods.

The commission was more cautious, however, with respect to nonhydro facilities. Nonhydro facilities, smaller than 5 megawatts were offered long-run avoided cost estimates for 15 years, which facilities of 5 to 20 megawatts were offered long-run rates for 15 years, but subject to adjustment in the 10th year of the contract.

Units in excess of 20 megawatts were required to adjust avoided cost calculations in the 5th and 10th years of the contract. These larger facilities were also given the option of annually adjusted avoided cost rates with changes in avoided costs limited to a specified ban around the long-run avoided cost estimate.

Another option was offered in which the capacity portion of the long-run estimate was guaranteed for 15 years, with the energy portion to be indexed to the independent fuel market.

Nonhydro developers were also required to provide the contracted output for the entire term of the fixed payment schedule for facilities larger than 5 megawatts. The commission also required performance guarantees in the form of a capacity factor, target or availability level during critical peak times to be negotiated on a case-by-case basis.

I would like to briefly describe the three basic elements in our methodology of developing avoided costs. First, a generation capacity cost.

At the present time, New York has substantial excess generating capacity. We know, however, that we will eventually have to add capacity both to meet rising demand and replace existing plant. This new capacity may come from nonutility power production facilities, new utility plant, refurbishment of existing utility plant, Canadian imports, or conservation in load management.

In our avoided cost calculations, we used the cost of building and operating a coal-fired central generating plant to measure future production costs. Thus, around the turn of the century, when we estimate that additional capacity will have to be added, our avoided cost estimates equal, on a kilowatthour basis, our forecasts of what a coal-fired generation unit would cost at that time

It would be incorrect, however, to include in avoided costs today the full cost of a new coal-fired plant, given our current excess capacity. On the other hand, additional capacity is of some value, even now, because it helps to reduce, although not significantly, the likelihood of a shortage.

Currently, however, generation capacity credits is a very small component of our avoided cost numbers.

Avoided energy costs are based on a very detailed and elaborate simulation of the operation of the New York power pool, the central dispatching entity in New York State. Thus, we use the energy cost avoided for the State as a whole, rather than the energy cost avoided by a particular utility.

Avoided transmission and distribution costs are estimated by examining past construction expenditure and future construction plans for later growth.

The commission has taken other actions to assist in development of alternate energy production. We developed front-loaded contracts, which allow payments to developers above avoided costs in the early years of the contract, to be paid back with interest in later years of the contract.

These contracts facilitate the financing of alternate power facilities, while protecting ratepayers from overpaying over the life of the contract. We have also ordered a 10-year phase-in of full avoided cost rates for all capacity not eligible for avoided cost under the law, to encourage the continued operation of such facilities.

Legislation has been enacted in New York which goes beyond the requirements of PURPA and provides a floor for payments to alternate energy producers of 6 cents per kilowatthour should avoided costs be lower than that amount.

In fact, avoided costs in New York have generally been less than 6 cents per kilowatthour and we expect them to continue to be lower than 6 cents for several years.

Insofar as this legislation requires payments in excess of avoided costs, it provides a subsidy for alternate energy facilities. When this legislation was enacted in 1980, oil prices were high and rising and there was great concern in New York about our inordinate reliance on imported oil for electricity production.

While we generally opposed the subsidization of one energy form, the 6-cent law has acted as a spur to the development of small power in New York and has not caused substantial increases in rates.

However, our State legislature is currently considering further legislation which would increase the minimum sale price from 6 to 8 cents per kilowatt-hour, a 33-percent increase. The bill would also mandate a specific methodology for calculating avoided costs which would ensure payment substantially in excess of what is economically justifiable.

In strenuously opposing this legislation, I pointed out that in addition to forcing ratepayers to make excessive payments for power we do not need, the proposed legislation would hinder sound energy planning because it would provide favored treatment for one supply option alternate power production when all options should be considered on an equal basis.

Thus far, alternate energy production has not had a significant impact on the operation and reliability of the utility systems in New York. Of the contracts already approved by the commission, a substantial majority is hydro; these facilities are in diverse locations throughout the State.

The development of hydropower in New York has not had a significant environmental impact. Nearly all of the hydro contracts we have approved have involved existing sites rather than the construction of new facilities, and the commission has generally expressed the view that there are sufficient protections under both

State and Federal law which will prevent the development of environmentally unacceptable facilities.

We believe that no one approach to meeting our future energy needs should be favored above any other approach. Rather, in determining how best to meet future energy needs, we should objectively and fairly examine and weigh the relative merits of the various options, including their ability to meet standards for system reliability and their costs and environmental impact.

The different options to be considered include energy conservation, load management, alternate energy production, energy imports, as well as utility and nonutility construction of small or large central generating stations under traditional regulatory rules, or revised rules, which would partially or fully deregulate the generation of electricity.

In its current form, PURPA requires the elimination of barriers to the development of alternate energy production and requires that a fair price, measured by avoided future utility costs, be paid for this energy. As a result of PURPA, alternate energy production has been substantially increased. Our sources of power production have been diversified and our reliance on oil reduced.

Importantly, PURPA does not require that alternate energy production be favored over any other means meeting our energy needs. I believe that this evenhanded approach is correct. It should not be changed.

The energy needs of the different States vary greatly and the proper responses to those needs will also vary greatly. To the greatest extent possible, States should continue to have maximum flexibility in implementing the objectives of PURPA and be free to develop energy policies which are best suited to their particular needs.

Thank you.

[The prepared statement of Mr. Gioia follows:]

TESTIMONY ON THE IMPLEMENTATION OF PURPA

PAUL L. GIOIA, CHAIRMAN
NEW YORK STATE PUBLIC SERVICE COMMISSION

BEFORE THE

UNITED STATES SENATE COMMITTEE ON ENERGY
AND NATURAL RESOURCES

WASHINGTON, D.C.
JUNE 6, 1986

I. INTRODUCTION

THERE HAS BEEN SIGNIFICANT PROGRESS IN NEW YORK STATE SINCE THE ADOPTION OF THE PURPA LEGISLATION IN THE PROMOTION OF ALTERNATE FORMS OF ENERGY PRODUCTION. THE 266 ON-SITE GENERATION CONTRACTS APPROVED BY THE COMMISSION TO DATE TOTAL APPROXIMATELY 537 MEGAWATTS, AN AMOUNT APPROACHING THE 634 MEGAWATT CAPACITY OF THE ONLY LARGE CENTRAL GENERATING STATION BUILT IN NEW YORK DURING THIS PERIOD. IN ADDITION, THERE ARE CONTRACTS CURRENTLY PENDING OR IN NEGOTIATION REPRESENTING AN ADDITIONAL 1,300 MW OF CAPACITY.

THIS DEVELOPMENT HAS COME ABOUT AS A RESULT OF THE COMMISSION'S IMPLEMENTATION OF PURPA AND RELATED STATE LEGISLATION, AS WELL AS ITS OWN INITIATIVES TO ENCOURAGE ALTERNATE ENERGY PRODUCTION. IT IS IMPORTANT TO NOTE THAT THIS DEVELOPMENT HAS OCCURRED IN NEW YORK DURING A PERIOD WHEN OUR GENERATING CAPACITY EXCEEDS PEAK DEMAND BY 40%.

II. COMPLIANCE WITH THE REQUIREMENTS OF PURPA SECTION 210 IN NEW YORK STATE

THE NEW YORK STATE PUBLIC SERVICE COMMISSION ACTED IN 1981 AND 1982 IN ITS CON EDISON ON-SITE GENERATION CASE TO ESTABLISH THE FULL-AVOIDED COST STANDARD TO PROVIDE DEVELOPERS WITH QUALIFYING FACILITIES THE MAXIMUM POSSIBLE ENCOURAGEMENT CONSISTENT WITH ENSURING THAT THE COSTS BORNE BY RATEPAYERS WOULD BE NO HIGHER THAN IF THE ELECTRICITY WERE PRODUCED BY A UTILITY. IN ITS ORDER IN THAT CASE, THE COMMISSION CONCLUDED THAT MARGINAL COSTS SHOULD BE USED FOR THE

PURPOSES OF DETERMINING AVOIDED COSTS. IT ALSO CONCLUDED THAT MARGINAL CAPACITY COSTS, WHICH VARY WITH SYSTEM PEAKS, WOULD BE DEEMED AVOIDABLE TO THE EXTENT THAT ON-SITE GENERATORS DELIVER POWER DURING PEAK PERIODS. THE COMMISSION REQUIRED UTILITIES TO SUBMIT NON-DISCRIMINATORY RATES FOR BACK-UP AND SUPPLEMENTAL SERVICES TO ON-SITE GENERATORS AND IT ORDERED UTILITIES TO ENTER INTO LONG-TERM CONTRACTS WITH DEVELOPERS. AVOIDED COST TARIFFS FOR ALL OF THE STATE'S UTILITIES HAVE SINCE BEEN APPROVED AND AVOIDED COSTS HAVE BEEN RELITIGATED IN EACH SUBSEQUENT UTILITY RATE CASE.

THE COMMISSION WAS THEN URGED TO DEVELOP LONG-RUN AVOIDED COST ESTIMATES, WHICH WOULD COMMIT THE COMMISSION TO SPECIFIC AVOIDED COST NUMBERS FOR YEARS INTO THE FUTURE. THE OBVIOUS DISADVANTAGE OF LONG-RUN NUMBERS IS THAT THE COMMISSION IS REQUIRED TO MAKE LONG-TERM ESTIMATES FOR FACTORS, SUCH AS FUEL COSTS, DEMAND GROWTH AND INTEREST RATES, WHICH ARE INHERENTLY UNCERTAIN -- AND WOULD BE BOUND BY ITS ESTIMATES -- EVEN IF CIRCUMSTANCES CHANGED SUBSTANTIALLY. ON THE OTHER HAND, LONG-RUN ESTIMATES FACILITATE THE FINANCING OF ALTERNATE POWER PROJECTS AND FREE DEVELOPERS FROM HAVING TO RELITIGATE AVOIDED COSTS ON AN ANNUAL BASIS. WITH RESPECT TO THE RISK, IT CAN BE ARGUED THAT THE RISK IS ASSUMED BY THE DEVELOPERS AS WELL AS THE COMMISSION AND THAT IT IS NOT UNLIKE THE RISK ASSUMED WHEN A LARGE UTILITY PROJECT IS UNDERTAKEN.

THE COMMISSION DECIDED TO DEVELOP LONG-RUN NUMBERS AND COMMENCED A PROCEEDING WITH RESPECT TO NIAGARA MOHAWK WHICH EVENTUALLY RESULTED IN A SETTLEMENT AGREEMENT. UNDER THE TERMS OF THE SETTLEMENT PRODUCERS WHO DELIVERED POWER AT THE DISTRIBUTION LEVEL WOULD BE PAID 5.5 CENTS PER KWH IN 1985, INCREASING STEADILY TO 19.6 CENTS PER KWH IN 2000. THIS EQUATED TO A LEVELIZED PAYMENT OF 7.67 CENTS PER KWH FOR THE TEN YEARS ENDING IN 1994.

THE COMMISSION DECIDED TO LIMIT THE BINDING EFFECT OF THESE LONG-RUN NUMBERS TO 15 YEARS, AND TO FACILITIES OF 20 MEGAWATTS OR LESS. THE NUMBERS WERE TO BE RECALCULATED IN TWO YEARS BUT THE COMMISSION RESERVED THE RIGHT TO REVISE THE NUMBERS SOONER IF THERE WERE MAJOR CHANGES IN FACTORS AFFECTING THE CALCULATION OF AVOIDED COSTS. IN FACT, PRIMARILY BECAUSE OF REDUCED FUEL PRICES, THE COMMISSION WAS PETITIONED BY NIAGARA MOHAWK TO REVIEW THE LONG-RUN SETTLEMENT NUMBERS, AND IT UNDERTOOK SUCH A REVIEW.

THE COMMISSION RECOGNIZED THAT ITS REVIEW OF THE SETTLEMENT NUMBERS WOULD PRESENT PROBLEMS FOR PROJECTS ALREADY IN THE PIPELINE AND AGREED TO ALLOW HYDRO PROJECTS, UNDER 20 MW, TO CONTINUE TO USE THE SETTLEMENT NUMBERS, PROVIDED THAT POWER WAS PRODUCED BY THE END OF 1986. THIS DEADLINE WAS LATER EXTENDED TO THE END OF 1987. THE COMMISSION GRANTED SPECIAL TREATMENT FOR SMALL HYDRO PROJECTS BECAUSE OF THE SPECIAL BENEFITS THEY PROVIDE, WHICH INCLUDE: (1) LONGER USEFUL LIVES, (2) FREEDOM FROM FLUCTUATIONS IN FUEL PRICES, (3) LOWER

OPERATING COSTS, (4) ENVIRONMENTAL SUPERIORITY TO OTHER ALTERNATIVES, AND (5) REDUCED RELIANCE ON OIL AND GAS.

FOLLOWING ITS REVIEW, THE COMMISSION ADOPTED A NEW LONG-RUN FORECAST FOR NIAGARA MOHAWK AS WELL AS FOR THE OTHER MAJOR NEW YORK UTILITIES. THESE LONG-RUN NUMBERS WERE SUBSTANTIALLY LOWER THAN THE SETTLEMENT NUMBERS, PRIMARILY BECAUSE OF LOWER FUEL COST ESTIMATES. FOR NIAGARA MOHAWK, AVOIDED COST FOR POWER DELIVERED AT THE DISTRIBUTION LEVEL WAS SET AT 4.28 CENTS PER KWH IN 1986, INCREASING TO 14.6 CENTS PER KWH IN 2001. THIS EQUATES TO A LEVELIZED PAYMENT OF 5.582 CENTS PER KWH FOR THE TEN YEARS ENDING IN 1995.

THE COMMISSION ALSO PROMULGATED STANDARD CONTRACT OFFERS -- WHICH VARY DEPENDING UPON THE TYPE OF FACILITY AND SIZE. HYDRO FACILITIES WERE TREATED MOST FAVORABLY. AMONG THE OPTIONS OFFERED WERE 15 YEAR CONTRACTS WITH LONG-RUN ESTIMATES, REGARDLESS OF FACILITY SIZE. THEY WERE ALSO ALLOWED CONTRACTS WITH LEVELIZED LONG-RUN NUMBERS FOR 15 YEARS, AND NUMBERS IN EXCESS OF THE LONG-RUN NUMBERS FOR FACILITIES WHICH COULD GUARANTEE POWER ON PEAK PERIODS. THE COMMISSION WAS MORE CAUTIOUS WITH RESPECT TO NON-HYDRO FACILITIES.

NON-HYDRO FACILITIES SMALLER THAN 5 MW WERE GRANTED LONG-RUN AVOIDED COST ESTIMATES FOR 15 YEARS, WHILE FACILITIES OF 5 MW TO 20 MW WERE GIVEN LONG-RUN AVOIDED COST RATES FOR 15 YEARS, BUT SUBJECT TO ADJUSTMENT IN THE 10TH YEAR OF THE CONTRACT. UNITS IN EXCESS OF 20 MW WERE ALLOWED LONG-RUN AVOIDED COST RATES FOR 15 YEARS, BUT SUBJECT TO ADJUSTMENT IN THE FIFTH AND TENTH YEARS OF THE

CONTRACT. THESE LARGER FACILITIES WERE ALSO GIVEN THE OPTION OF ANNUALLY ADJUSTED AVOIDED COST RATES WITH CHANGES IN AVOIDED COST LIMITED WITHIN A SPECIFIED RANGE FROM THE LONG-RUN AVOIDED COST ESTIMATE. ANOTHER OPTION WAS OFFERED IN WHICH THE CAPACITY PORTION OF THE LONG-RUN ESTIMATE WAS GUARANTEED FOR 15 YEARS, WITH THE ENERGY PORTION TO BE INDEXED TO INDEPENDENT FUEL MARKETS.

FOR THOSE NON-HYDRO DEVELOPERS OPTING FOR LONG-RUN AVOIDED COST NUMBERS, THE COMMISSION ALSO REQUIRED THAT THE CONTRACTED OUTPUT BE PROVIDED FOR THE ENTIRE TERM OF THE FIXED PAYMENT SCHEDULE. FOR SUCH FACILITIES GREATER THAN 5 MW, THE COMMISSION ALSO REQUIRED PERFORMANCE GUARANTEES, IN THE FORM OF A CAPACITY FACTOR TARGET OR AVAILABILITY LEVEL DURING CRITICAL PEAK TIMES, TO BE NEGOTIATED ON A CASE-BY-CASE BASIS.

THE THREE MAJOR COMPONENTS OF THE COMMISSION'S AVOIDED COST CALCULATION ARE (1) GENERATION INVESTMENT, (2) ENERGY AND (3) TRANSMISSION AND DISTRIBUTION.

AVOIDED GENERATION CAPACITY COSTS

AT THE PRESENT TIME, NEW YORK HAS SUBSTANTIAL EXCESS GENERATING CAPACITY. THIS MEANS WE CAN MEET OUR DEMANDS FOR ELECTRICITY, MAINTAIN AN ADEQUATE RESERVE, AND STILL HAVE A SUBSTANTIAL AMOUNT OF GENERATING CAPACITY THAT IS UNUSED. WE KNOW, HOWEVER, THAT NEW YORK STATE WILL EVENTUALLY HAVE TO ADD CAPACITY BOTH TO MEET RISING DEMAND AND TO REPLACE EXISTING PLANT.

THIS NEW CAPACITY MAY COME FROM NON-UTILITY POWER PRODUCTION FACILITIES, NEW UTILITY PLANT, REFURBISHMENT OF EXISTING UTILITY PLANT, CANADIAN IMPORTS OR CONSERVATION AND LOAD MANAGEMENT. IN OUR AVOIDED COST CALCULATIONS WE USE THE COST OF BUILDING AND OPERATING A COAL-FIRED CENTRAL GENERATION PLANT TO MEASURE FUTURE PRODUCTION COSTS. THUS, UNDER THE COMMISSION'S RECENTLY ISSUED PROJECTION OF AVOIDED COSTS, AROUND THE TURN OF THE CENTURY, WHEN WE ESTIMATE THAT ADDITIONAL CAPACITY WILL HAVE TO BE ADDED, OUR AVOIDED COST ESTIMATES EQUAL, ON A KILOWATT HOUR BASIS, OUR FORECAST OF WHAT A COAL-FIRED GENERATION UNIT WOULD COST AT THAT TIME.

IT WOULD NOT BE CORRECT, HOWEVER, TO INCLUDE IN AVOIDED COSTS TODAY, THE FULL COST OF A NEW COAL-FIRED PLANT, GIVEN OUR CURRENT EXCESS CAPACITY. ON THE OTHER HAND, ADDITIONAL CAPACITY IS OF SOME VALUE, EVEN NOW, BECAUSE IT HELPS TO.REDUCE, ALTHOUGH NOT SIGNIFICANTLY, THE LIKELIHOOD OF A SHORTAGE. IN THIS PERIOD OF EXCESS CAPACITY IN NEW YORK STATE, WE ESTIMATE THE CURRENT VALUE OF CAPACITY BASED UPON HOW ADDITIONAL CAPACITY WOULD REDUCE THE LIKELIHOOD OF AN OUTAGE. THE ACTUAL CALCULATION IS BASED UPON AN ELABORATE SIMULATION OF THE OPERATION OF THE NEW YORK POWER POOL, BUT IN SIMPLE TERMS WHAT WE DO IS CALCULATE THE EXTENT TO WHICH ADDITIONAL CAPACITY WOULD REDUCE THE LIKELIHOOD OF AN OUTAGE GIVEN OUR CURRENT SURPLUS CONDITION, COMPARE THAT TO HOW ADDITIONAL CAPACITY WOULD AFFECT OUTAGES IF WE HAD ONLY ENOUGH CAPACITY TO MEET OUR TARGET RESERVE MARGIN, AND THEN ADJUST THE COST OF NEW PEAKING CAPACITY BY THE RATIO

OF THESE TWO VALUES. IN MAKING THIS CALCULATION, WE ARE STATING THAT IN A SYSTEM WITH AN OPTIMAL LEVEL OF GENERATION RESERVE, THE VALUE OF GENERATION CAPACITY IS THE ANNUAL COST OF NEW PEAKING CAPACITY.

AVOIDED ENERGY COSTS

AVOIDED ENERGY COSTS ARE ALSO ESTIMATED BASED UPON A VERY DETAILED AND ELABORATE SIMULATION OF THE OPERATION OF THE NEW YORK POWER POOL, THE CENTRAL DISPATCHING ENTITY IN NEW YORK STATE. THUS, WE USE THE ENERGY COST AVOIDED FOR THE STATE AS A WHOLE, RATHER THAN THE COST AVOIDED BY THE PARTICULAR UTILITY, AS THE MEASURE OF AVOIDED ENERGY COST. EVERY GENERATING UNIT THAT IS USED IN THE POWER POOL IS INCLUDED AS PART OF THE DATA BASE USED FOR THE SIMULATION. BASICALLY, THE SIMULATION PROVIDES US WITH ESTIMATES OF WHAT IT WOULD COST TO MEET AN ADDITIONAL UNIT OF DEMAND, IN TERMS OF PRODUCTION COSTS, AT ANY HOUR OVER THE YEAR WITHIN THE ENTIRE POWER POOL. THIS MODEL IS ALSO USED TO FORECAST AVOIDED COSTS OUT INTO THE FUTURE, AND LIKEWISE CAN PRODUCE HOURLY COST ESTIMATES FOR EVERY YEAR OF THE FORECAST PERIOD.

NEAR THE END OF THE CENTURY WHEN THE COST OF NEW COAL-FIRED PLANT IS USED THAT COST WOULD REPRESENT BOTH MARGINAL CAPACITY AND MARGINAL ENERGY COST.

AVOIDED TRANSMISSION AND DISTRIBUTION COSTS

AVOIDED TRANSMISSION AND DISTRIBUTION COSTS ARE ESTIMATED BY EXAMINING PAST CONSTRUCTION EXPENDITURES AND FUTURE CONSTRUCTION PLANS RELATED TO GROWTH. THE COMMISSION HAS NOT DIFFERENTIATED

AVOIDED TRANSMISSION COSTS BY GEOGRAPHICAL LOCATION BECAUSE RETAIL RATES ARE NOT SO DIFFERENTIATED. IT DOES APPEAR, HOWEVER, THAT AVOIDED TRANSMISSION COSTS DO DIFFER AND STUDIES ARE BEING DONE TO DETERMINE THE EXTENT OF THE VARIATION.

III. NEW YORK STATE ACTIONS BEYOND THE REQUIREMENTS OF PURPA

IN ADDITION TO DEVELOPING SHORT-RUN AND LONG-RUN AVOIDED COST NUMBERS, REQUIRING UTILITIES TO PROVIDE REASONABLY PRICED BACK-UP RATES, AND ESTABLISHING REASONABLE INTERCONNECTION REQUIREMENTS, THE COMMISSION HAS TAKEN OTHER ACTIONS TO ASSIST IN THE DEVELOPMENT OF ALTERNATE ENERGY PRODUCTION.

FIRST, THE NEW YORK COMMISSION DEVELOPED A FRONT-LOADED CONTRACT, WHICH ALLOWS PAYMENTS TO DEVELOPERS ABOVE AVOIDED COSTS IN THE EARLY YEARS OF THE CONTRACT, TO BE PAID BACK WITH INTEREST IN THE LATER YEARS OF THE CONTRACT. THESE CONTRACTS FACILITATE THE FINANCING OF ALTERNATE POWER FACILITIES, WHILE PROTECTING RATEPAYERS FROM OVERPAYING OVER THE LIFE OF THE CONTRACT. TO PROVIDE SECURITY, ACCUMULATED UP-FRONT PAYMENTS ARE LIMITED TO THE INVESTMENT IN THE FACILITY. IN ADDITION, THE UTILITY IS GRANTED THE RIGHT TO TAKE OVER THE PROJECT IF THE OWNER CEASES TO OPERATE IT.

THE COMMISSION HAS APPROVED FRONT-LOADING ONLY FOR HYDRO CONTRACTS. HOWEVER, DEVELOPERS OF OTHER TYPES OF FACILITIES, INCLUDING LARGE GAS AND COAL-FIRED CO-GENERATION FACILITIES, ARE SEEKING SIMILAR CONTRACT TERMS. BECAUSE ADVANCE PAYMENTS FOR SUCH

PROJECTS WOULD BE MUCH MORE SUBSTANTIAL THAN FOR SMALL HYDRO FACILITIES AND BECAUSE THEIR CONTINUED ECONOMIC OPERATION IS MUCH LESS CERTAIN, THE COMMISSION HAS INDICATED THAT IT WOULD REQUIRE FIRMER SECURITY TO ENSURE REPAYMENT OF THE EXCESS PAYMENTS, IN THE FORM OF INSURANCE, A BOND, OR A LETTER OF CREDIT.

THE NEW YORK COMMISSION HAS ALSO ORDERED THE PHASE-IN OF AVOIDED COST RATES FOR "OLD" CAPACITY, NOT ELIGIBLE FOR AVOIDED COST PAYMENTS UNDER THE LAW, TO ENCOURAGE THE CONTINUED OPERATION OF SUCH FACILITIES. IN CASES WHERE AN EXISTING CONTRACT EXPIRES OR WHERE PERMITTED BY AN EXPRESS PROVISION IN AN EXISTING AGREEMENT, A PRODUCER OPERATING AN OTHERWISE QUALIFYING FACILITY, CONSTRUCTION OF WHICH COMMENCED PRIOR TO NOVEMBER 9, 1978, MAY NEGOTIATE A SPECIAL CONTRACT FOR A RATE THAT WOULD IN 1986 BE SET AT 50% OF FULL AVOIDED COSTS AND IN EACH SUCCESSIVE YEAR INCREASE BY 5 PERCENTAGE POINTS SO THAT BY 1996, ALL SUCH FACILITIES WOULD RECEIVE 100 PERCENT OF FULL AVOIDED COSTS.

LEGISLATION HAS BEEN ENACTED IN NEW YORK WHICH GOES BEYOND THE REQUIREMENTS OF PURPA AND PROVIDES A FLOOR FOR PAYMENTS TO ALTERNATE ENERGY PRODUCERS OF 6 CENT PER KWH -- SHOULD AVOIDED COST BE LOWER THAN THAT AMOUNT. IN FACT, AVOIDED COSTS IN NEW YORK HAVE GENERALLY BEEN LESS THAN 6 CENTS PER KWH -- AND WE EXPECT THEM TO CONTINUE TO BE LOWER THAN 6 CENTS FOR THE NEXT SEVERAL YEARS. INSOFAR AS THIS LEGISLATION REQUIRES PAYMENTS IN EXCESS OF AVOIDED COSTS -- IT PROVIDES A SUBSIDY FOR ALTERNATE ENERGY FACILITIES. WHEN THIS LEGISLATION WAS ENACTED, IN 1980, OIL PRICES WERE HIGH AND RISING AND THERE WAS GREAT CONCERN IN NEW YORK ABOUT OUR INORDINATE RELIANCE ON IMPORTED OIL FOR ELECTRICITY PRODUCTION. WHILE WE GENERALLY OPPOSE THE SUBSIDIZATION OF ANY ONE ENERGY FORM, THE 6 CENT LAW HAS ACTED AS

A SPUR TO THE DEVELOPMENT OF THE SMALL POWER INDUSTRY IN NEW YORK AND, HAS NOT CAUSED SUBSTANTIAL INCREASES IN RATES.

HOWEVER, OUR STATE LEGISLATURE IS CURRENTLY CONSIDERING FURTHER LEGISLATION WHICH WOULD INCREASE THE MINIMUM SALES PRICE FROM 6 CENTS TO 8 CENTS PER KWH, A 33% INCREASE. THE BILL WOULD ALSO MANDATE A SPECIFIC METHODOLOGY FOR CALCULATING AVOIDED COSTS WHICH WOULD ENSURE PAYMENTS SUBSTANTIALLY IN EXCESS OF WHAT IS ECONOMICALLY JUSTIFIABLE. IN STRENUOUSLY OPPOSING THIS LEGISLATION, I POINTED OUT THAT, IN ADDITION TO FORCING RATEPAYERS TO MAKE EXCESSIVE PAYMENTS FOR POWER WE DO NOT NEED, THE PROPOSED LEGISLATION WOULD HINDER SOUND ENERGY PLANNING BECAUSE IT WOULD PROVIDE FAVORED TREATMENT FOR ONE SUPPLY OPTION -- ALTERNATE POWER PRODUCTION -- WHEN ALL OPTIONS, INCLUDING CONSERVATION, LOAD MANAGEMENT, CANADIAN IMPORTS AND UTILITY CONSTRUCTION, SHOULD BE CONSIDERED ON AN EQUAL BASIS.

IV. THE EFFECTS OF PURCHASES ON THE OPERATION AND RELIABILITY OF UTILITY SYSTEMS

THUS FAR, ALTERNATE ENERGY PRODUCTION HAS NOT HAD A SIGNIFICANT IMPACT ON THE OPERATION AND RELIABILITY OF UTILITY SYSTEMS IN NEW YORK. OF THE CONTRACTS ALREADY APPROVED BY THE COMMISSION, THE SUBSTANTIAL MAJORITY OF THE CONTRACTED-FOR-CAPACITY IS HYDRO. THERE ARE OVER 90 CONTRACTS FROM NUMEROUS SMALL HYDRO FACILITIES IN DIVERSE LOCATIONS AROUND THE STATE. THE MAJORITY OF THESE FACILITIES INTERCONNECT AT THE DISTRIBUTION OR SUBTRANSMISSION LEVEL AND, THUS, HAVE NO MAJOR EFFECT ON SYSTEM RELIABILITY. THE

LARGEST FACILITY CONTRACTED FOR TO DATE IS THE 55 MW WESTCHESTER REFUSE PROJECT WHICH IS OPERATED ON A POOL DISPATCH BASIS. ACCORDINGLY, THAT FACILITY'S EFFECT ON SYSTEM RELIABILITY IS MINIMIZED AS WELL.

THE STATE IS CURRENTLY CONSIDERING APPLICATIONS OF LARGER FACILITIES IN EXCESS OF 200 MW. WE EXPECT THAT THESE AND LARGER-SIZED REFUSE FACILITIES MAY POSE GREATER OPERATIONAL AND RELIABILITY CONCERNS THAN HAVE THE FACILITIES APPROVED BY THE COMMISSION TO DATE, AND WE EXPECT TO UNDERTAKE A STUDY OF THIS ISSUE IN THE NEAR FUTURE.

V. THE ENVIRONMENTAL IMPACTS OF CONSTRUCTION AND OPERATION OF QUALIFYING HYDRO ELECTRIC FACILITIES

THE DEVELOPMENT OF HYDRO POWER IN NEW YORK HAS NOT HAD A SIGNIFICANT ENVIRONMENTAL IMPACT. NEARLY ALL OF THE 90-PLUS HYDRO CONTRACTS THAT HAVE BEEN APPROVED BY THE COMMISSION TO DATE HAVE INVOLVED EXISTING SITES. THE MOST ECONOMIC FACILITIES ARE THOSE NEEDING ONLY REFURBISHMENT OF A DAM OR REPLACEMENT AND REPAIR OF GENERATORS AND OTHER EQUIPMENT, RATHER THAN THE CONSTRUCTION OF AN ENTIRELY NEW FACILITY.

IN THE COMMISSION'S MOST RECENT LONG-RUN AVOIDED COST CASE, SPECIFIC CONSIDERATION WAS GIVEN TO THE QUESTION OF WHETHER STANDARD OFFERS APPROVED THERE SHOULD BE MADE AVAILABLE TO HYDRO FACILITIES ON A NEW SITE OR ONE THAT WOULD BE A SUBSTANTIALLY ENLARGED VERSION OF AN EXISTING STRUCTURE. THE COMMISSION REASONED THAT ADEQUATE PROTECTIONS ARE NOW IN PLACE IN THE STATE TO ASSURE THAT ENVIRONMENTALLY

UNACCEPTABLE FACILITIES WOULD NOT BE BUILT EVEN WERE AN ENTIRELY NEW FACILITY REQUIRED.

VI. NEED FOR MODIFICATIONS OF PURPA

I BELIEVE THAT NO ONE APPROACH TO MEETING OUR FUTURE ENERGY NEEDS SHOULD BE FAVORED ABOVE ANY OTHER APPROACH. RATHER, IN DETERMINING HOW BEST TO MEET FUTURE ELECTRICITY NEEDS WE SHOULD OBJECTIVELY AND FAIRLY EXAMINE AND WEIGH THE VARIOUS OPTIONS, INCLUDING THE ABILITY TO MEET STANDARDS FOR SYSTEM RELIABILITY AND COST AND ENVIRONMENTAL IMPACTS. THE DIFFERENT OPTIONS TO BE CONSIDERED INCLUDE ENERGY CONSERVATION, LOAD MANAGEMENT, ALTERNATE ENERGY PRODUCTION, CANADIAN IMPORTS, AS WELL AS UTILITY AND NON-UTILITY CONSTRUCTION OF SMALL OR LARGE CENTRAL GENERATING STATIONS UNDER TRADITIONAL REGULATORY RULES, OR REVISED RULES WHICH WOULD PARTIALLY OR FULLY DEREGULATE THE GENERATION OF ELECTRICITY.

IN ITS CURRENT FORM, PURPA REQUIRES THE ELIMINATION OF BARRIERS TO THE DEVELOPMENT OF ALTERNATE ENERGY PRODUCTION AND REQUIRES THAT A FAIR PRICE, MEASURED BY AVOIDED UTILITY COSTS, BE PAID FOR THIS ENERGY. AS A RESULT OF PURPA, ALTERNATE ENERGY PRODUCTION HAS BEEN SUBSTANTIALLY INCREASED, OUR SOURCES OF POWER PRODUCTION HAVE BEEN DIVERSIFIED AND OUR RELIANCE ON OIL REDUCED. IMPORTANTLY, PURPA DOES NOT REQUIRE THAT ALTERNATE ENERGY PRODUCTION BE FAVORED OVER ANY OTHER MEANS FOR MEETING OUR ENERGY NEEDS. I BELIEVE THAT THIS EVEN-HANDED APPROACH IS CORRECT AND SHOULD NOT BE CHANGED. THE ENERGY NEEDS OF THE DIFFERENT STATES VARY GREATLY, AND THE PROPER RESPONSES

TO THOSE NEEDS MAY ALSO VARY GREATLY. TO THE GREATEST EXTENT POSSIBLE, STATES SHOULD CONTINUE TO BE FREE TO SOLVE THEIR PARTICULAR PROBLEMS IN THE WAY THEY DEEM MOST ECONOMICAL AND EFFICIENT WITHOUT BEING REQUIRED TO FAVOR ONE APPROACH OVER ANOTHER.

The CHAIRMAN. Thank you.

Dr. Thomas.

STATEMENT OF DR. DENNIS THOMAS, COMMISSIONER, PUBLIC UTILITY COMMISSION OF TEXAS

Dr. THOMAS. Thank you, Mr. Chairman. My name is Dennis Thomas. I am a member of the Texas Public Utility Commission.

My prepared testimony was organized around seven questions, but I would like to briefly cover three.

This is naturally all from the viewpoint of a State-level regulator, and we started out with not a terribly complicated strategy in Texas. Our strategy was that we wanted all the good cogeneration that was out there.

The difficulty then was to define the word "good" and, in general, our definition was the cogeneration that is cheaper than the planned utility generation, assuming equal reliability and cost.

Therefore, we adopted a market-based strategy, where we have set a maximum avoided cost for each utility, based upon the next unit they plan to build. The utilities then negotiate with the cogenerators below that cost. Our current discounts are in the range of 7 to 24 percent. We are current tracking 10,000 megawatts of cogeneration over the next 10 years. Of that amount, 3,000 megawatts exist and, of the 3,000, 1,500 is under long-term contract. We have an additional 1,500, which is under construction.

To put those numbers in context for you, our current generating capacity in the State is about 50,000 megawatts. So, of the 3,000 that is going into the grid right now, that is about 6 percent.

I would expect that cogeneration will make up about 10 to 15 percent of our generation load in the next 10 years.

This market-based approach was possible, I think, because of the tremendous potential for cogeneration and the fact that it tends to come to us in large chunks, 200 to 400 megawatts. It is also possible because our cogeneration comes from big companies who are sophisticated players, and also because we have gone through 4 years of intense and bitter complaint dockets before the public utility commission in which I think expectations on all sides has come a little bit closer to reality.

The utility companies understand that they are going to have to buy cogeneration, and the cogenerators understand that any sort of religious zeal and approach to getting full avoided costs is no longer possible.

There are other strategies we could have pursued which I think you see evident in other States. We could have said that cogeneration would replace all new utility generation. We rejected that. We could have assigned a certain percent of our generation mix that we wanted it to make up. We rejected that.

Or, we could have said we want all the cogeneration that is available at a specific price, such as the standard offer approach.

I think it is important and something we have gone through to understand that when you select something like a market-based approach, you have inevitably ordered the priorities, and I think if you were to sit down and discuss our priorities right now, I would list them as, one, economic benefit to ratepayers; two, economic benefit to the area—in other words, creating and saving jobs; three, energy resource efficiency, including environment; and four, National security.

If you take those and compare them against the priorities that I think an objective person reading PURPA in 1978 would have listed, they would have listed national security first; second would be energy resource sufficiency; third would be the economic benefit to U.S. industry; and a distant fourth would be neutral impact on ratepayers.

Well, neutrality is fine in theory, but it just does not work in Texas. Neutrality in terms of impact on ratepayers, because cogeneration does bring added risk to the utility generation system. You have more players, and in Texas, it brings us to more dependence on fuel with volatile prices.

For that reason, we decided early on that for cogeneration to go, there had to be some benefit in it for the ratepayers, and the market-based approach, with very extensive negotiations between the utilities and the cogenerators, brought us that benefit in terms of discount.

In terms of the economic benefit to the area, we think we can show a number of the large petrochemicals, especially companies on the gulf coast, who have maintained plants in Texas and, it just comes down to a straight economic tradeoff since most of these are producing bulk chemicals; can they produce it better in Texas, or can they produce it better at one of their other plants in another State?

We believe that in several cases, cogeneration and the revenue they were able to achieve has made that difference.

In terms of resource sufficiency, cogeneration is a concern because it is delaying our move off of natural gas as a boiler fuel. In 1975, we were 95 percent dependent on natural gas. We are currently 70 percent. I hoped we would be in the range of 53 percent. Cogeneration will slow that up.

That is a concern, but because of the volatility of natural gas prices in the long run, but in the short run, we still think that cogeneration has some real economic benefits.

Let me conclude with the last question, which is, is the competitive market which we have established setting prices efficiently?

Before, in the period of 1980 to 1984, a major question was are the utilities bargaining in good faith? Essentially, I don't think that they were. They were stalling. We adopted a set of rules in 1984 that brought them to the table. Then I think the concern switches, and the concern is have we left sufficient flexibility with the utilities to allow them to be effective negotiators.

We have attempted to allow them to choose their business partners. We have attempted to allow them to select which fuel they want and to differentiate between cogenerators based upon fuel type and the quality of their cogeneration, and the quality of their fuel contract. I think quality of the fuel contract needs to be measured in terms of price, duration, whether or not they have a backup fuel, and whether or not they have a history of honoring the contract.

They differentiate on the basis of price and duration of the cogeneration, and they differentiate on whether or not the cogenerator will allow the utility to step in and operate the plant if the cogenerator goes out of business.

In terms of the current limits, which are obviously limits on full competition, in terms of the 50 percent ownership by utilities, a Federal limit, we don't have a problem if that is removed. That would obviously create regulatory problems, but I think that the greater flexibility it brings to the market would be a benefit, at least in our case.

In terms of no natural gas as a baseload fuel, we think that that should be removed, also. If baseload gas generation is cheaper than cogeneration, then it should be built. I don't think we will see a great surge. I don't think they can compete with the economics of the truly efficient cogenerators.

We have two State limits; one is on retail sales. We stand in the way of a cogeneration making retail sales. We feel that is necessary to protect the industrial load of our utilities, and the second is wheeling between cogenerators.

We require the utilities to wheel cogenerated power but only to other utilities. We have stood in the way of wheeling between cogenerators, once again, to protect the utilities' industrial base.

From our view, cogeneration gives us an 8 to 12 year window. We have four nuclear plants to assimilate. We are concerned about what the true economics of burning fossil fuel are going to be after the acid rain debate is completed, and it is a time in which we can see what the future of our refining and petrochemical industries are going to be in terms of demand. Cogeneration provides us a way to delay making the major decisions on new fuel types for that period of time.

[The prepared statement of Dr. Thomas follows:]

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Commissioner

Testimony By

Dennis Thomas, Ph.D.
Commissioner
Public Utility Commission of Texas

To

Committee on Energy and Natural Resources
United States Senate

June 5, 1986

COGENERATION POLICY ISSUES IN TEXAS

(Testimony by Dennis Thomas, Ph.D.
Commissioner, Public Utility Commission of Texas
before the U.S. Senate Committee on Energy and Natural Resources
June 5, 1986)

INTRODUCTION

The following comments are from the viewpoint, and carry the bias, of a state utility regulator. Since cogeneration is such a rapidly evolving issue in Texas, it is also important to identify the time frame. It has been eight years since the passage of PURPA, six years since the first cogeneration action by the Texas PUC, and two years since the Texas PUC became actively involved in encouraging cogeneration in Texas. My comments will be organized around seven questions:

1) Is there a right amount of cogeneration for Texas?
2) Does the Texas PUC have the priorities in the correct order?
3) Is there an optimum fuel diversity mix for Texas?
4) Is the competitive market setting the price efficiently in Texas?
5) Are the current limits on cogeneration still in the public interest?
6) Does current cogeneration policy in Texas have unintended side effects?
7) What does the future hold for cogeneration in Texas?

Is There a Right Amount of Cogeneration for Texas?

The current cogeneration policy in Texas, as established by rule at the Texas Public Utility Commission, is aimed at securing all the cogeneration that is cheaper than planned utility generation. The price comparison assumes the cogeneration is of equal reliability and equal quality of power. The price for cogeneration is set by market-based negotiations with a cap at a PUC approved maximum avoided cost for each company. Utility avoided costs are established in a docketed proceeding and are based upon the next unit the utility intends to build. In most cases, the figures are based on lignite capacity costs and lignite energy costs. PUC rules allow project payments to be levelized over the life of a project. The avoided cost dockets have been hotly contested but have, in most cases, ended in settlements.

Based upon the capacity payment contracts signed to date, the avoided cost rates have served more as a theoretical cap for payments. Because of an oversupply of cogeneration, utilities have been able negotiate for discounts of 7-24% under their avoided cost cap. Exhibit 1 shows a comparison of construction costs for recently completed fossil fuel generation plants, estimated construction costs for Texas nuclear plants, standard avoided cost rates set for Texas utilities, and estimates of recently negotiated cogeneration contract prices. Appendix A shows the current avoided cost rates set for companies in Texas.

The Texas PUC is currently tracking 10,370 MW of cogeneration, either existing or expected in the next 10 years. To put that number in perspective, the 1985 generation capacity allocated to Texas was in the range of 51,000 MW, so if all cogeneration currently being tracked were available today, it would constitute 20% of Texas generating capacity. That 10,000 MW is broken down as follows:

EXHIBIT 1

COGEN/CONVENTIONAL PLANT POWER COST COMPARISON

UTILITY	CONTRACT/PLANT TYPE	CAPACITY COST $/KW/YR	CAPACITY COST C/KWH	ENERGY COST C/KWH	TOTAL COST C/KWH
1988 COGEN COSTS:					
HL&P	AVOIDED COST	$159	2.1	3.2	5.3
HL&P	COGEN 1	$204	2.7	3.2	5.9*
HL&P	COGEN 2	$112	1.5	3.2	4.7
HL&P	COGEN 3	$59	0.8	3.2	4.0
TUEC	AVOIDED COST	$154	2.1	2.3	4.4
TUEC	COGEN 1	$60	0.8	3.3	4.1
TNP	AVOIDED COST	$131	1.8	2.3	4.1
1988 PLANT COSTS:					
GSU	RIVER BEND (NUCL)	$933	15.2	1.3	16.5
HL&P	STP 1 (NUCL)	$684	11.2	1.0	12.1
EPEC	PALO VERDE (NUCL)	$546	8.9	0.8	9.8
TUEC	COM PEAK 1 (NUCL)	$505	8.2	0.6	8.8
LCRA	FAYETTE 3 (LIG)	$343	5.6	2.8	8.3
HL&P	LIMESTONE 2 (LIG)	$266	4.3	2.5	6.8
WTU	OKLAUNION (COAL)	$161	2.6	2.1	4.7
SPS	TOLK 2 (COAL)	$125	2.0	2.1	4.1

* Signed before avoided cost rate set

NOTES:

1) DETAILS OF COGEN CONTRACTS ARE PROPRIETARY.
2) ONLY THE UTILITIES SHOWN HAVE AVOIDED CAPACITY COSTS PRIOR TO 1990. TUEC AVOIDED COST IS FOR 1989.
3) COGEN CAPACITY COSTS (C/KWH) BASED ON AN 85% CAPACITY FACTOR.
4) PLANT CAPACITY COSTS BASED ON A 22% FIXED CHARGE RATE AND 70% CAPACITY FACTOR.
5) PLANT ENERGY COSTS BASED ON PUC STAFF ESTIMATED FUEL COSTS.
6) PUC STAFF CONTACT: SCOTT NORWOOD, (512) 458-0107.

3,105 MW existing
1,799 MW under construction
2,659 MW proposed
2,807 MW potential
10,370 MW total 1986-1995

That breakdown is shown graphically on Exhibit 2. As one can see from Exhibit 2, of the 10,370 MW we are tracking, 3,105 MW already exist. Of the existing cogeneration, roughly half or 1,420 MW is under long-term contract with capacity payments; the remainder being paid for energy and, in many cases, a minimum capacity payment of $3 per month. Appendix A shows the cogeneration projects being tracked by status, fuel, and utility.

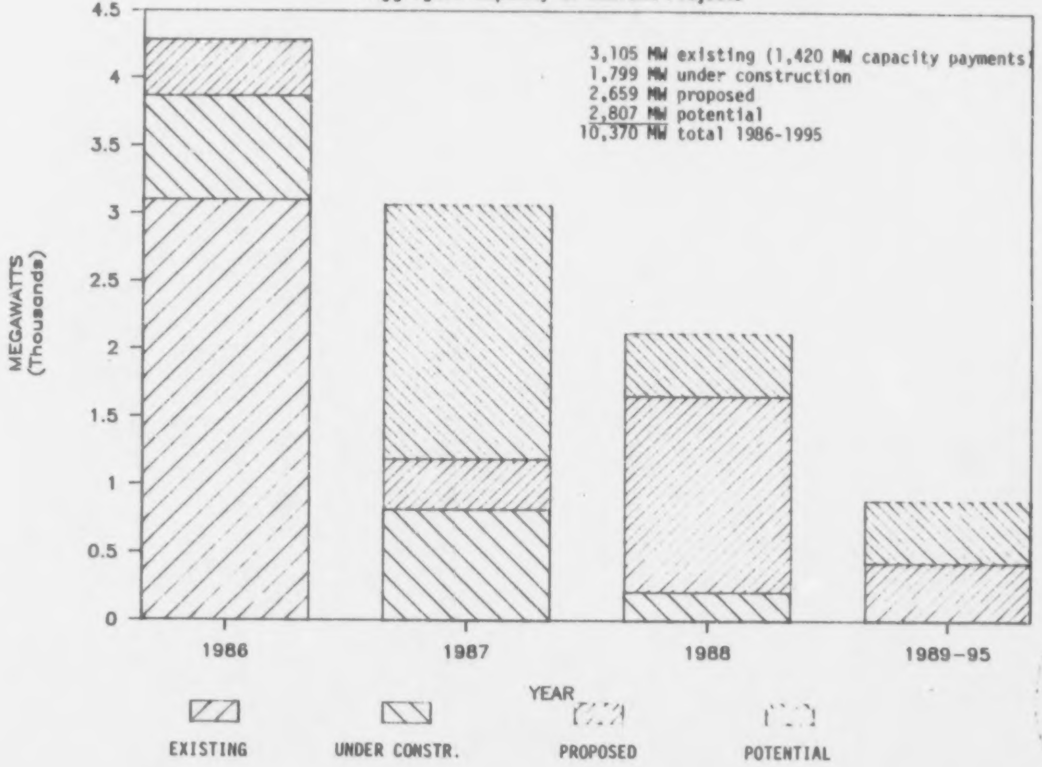
In summary, the Texas PUC has allowed the market to determine the amount of cogeneration that will exist in Texas. That was a conscious policy decision and to help put it in perspective, one might consider the other options that were available but were rejected. We might have decided to replace all new generation with cogeneration. Secondly, we could have set a specific MW target or a specific percentage of state generating capacity that we wanted cogeneration to comprise. Lastly, we could have set a target price through a standard offer and taken all cogeneration at or below that price.

The circumstances that led to selecting the market-based option included the fact that a great deal of cogeneration already existed in the petrochemical and refining industries on the Gulf Coast at the time the PUC was setting new rules in 1984. In other words, the potential for a competitive market existed. Secondly, most of the cogeneration in Texas was

EXHIBIT 2

STATUS OF COGENERATION IN TEXAS 1986–95

Aggregate Capacity of Current Projects



in large chunks in a range of 300-400 MW. Lastly, four years had elapsed since the time cogeneration first became an issue in Texas and the 1980 PUC laissez-faire rules. During that intervening time, the cogenerators and utilities had gotten to know one another and the measuring up and facing off process had already evolved through several bitter rounds of negotiation. As a result, expectations on both sides had moved closer to reality and the distance remaining between the parties was possible to span through negotiation. Without these factors, a market-based solution to determining the amount of cogeneration in Texas would likely not have been a feasible solution.

Does the Texas PUC Have the Priorities in the Correct Order?

The obvious question that arises in selecting a cogeneration strategy is, "Do we have the priorities in the correct order?" In my opinion, the actions taken by the PUC arrange the priorities as follows:

1) Economic benefit to ratepayers
2) Economic benefit to the geographic area and to industry (creating and saving jobs)
3) Energy/resource efficiency (includes environment)
4) National security

It is interesting to compare that set of priorities with the priorities one would have listed from reading the Public Utility Regulatory Policies Act (PURPA) in 1978:

1) National security

2) Energy/resource efficiency

3) Economic benefit to U.S. industry

4) Neutral impact on ratepayers

The list has reversed. That is not to say that national security and resource efficiency are no longer important, but instead that current decisions of the Texas PUC are more heavily oriented towards benefitting ratepayers and saving jobs. As a state with an oil-based economy, Texas is more aware than most of the dangers to national security that continue to exist from energy dependence, but we see few national programs in that direction or much stress on the national security goals of PURPA.

Is There an Optimum Fuel Diversity Mix for Texas?

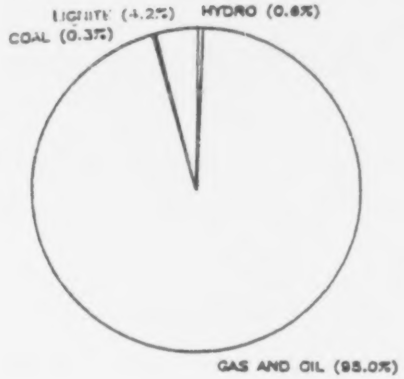
The two priorities that were first and second in 1978, national security and resource efficiency, and have now moved to the bottom of the list, are none the less still priorities. As can be seen on Exhibit 3, Texas has gone from 95% dependence on oil and gas as a boiler fuel in 1975 to 70% dependence in 1985, and is heading towards 53% dependence in 1995. The difference has been taken up by coal and lignite and then nuclear in 1995.

Texas was an early leader in limiting the use of natural gas as a boiler fuel. Now cogeneration would seem to move us back in the opposite direction. Although this movement back towards gas naturally causes a regulator some concern, I can justify it in terms of benefit to the ratepayer and in terms of jobs saved. At least the gas that is burned in a

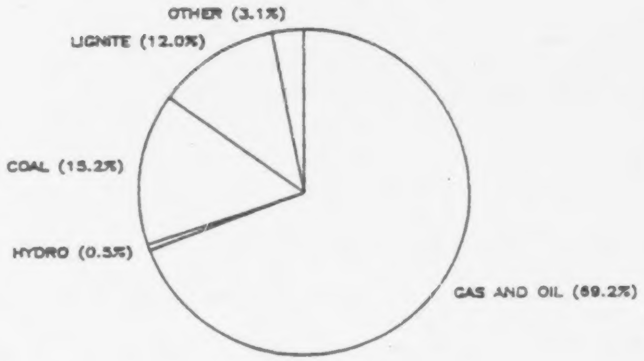
EXHIBIT 3

STATEWIDE CAPACITY BY FUEL TYPE

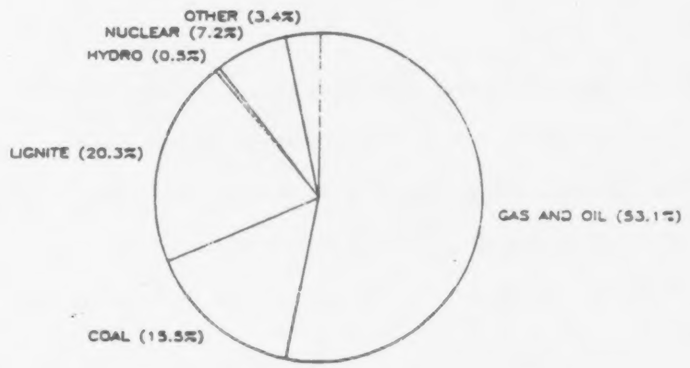
1975



1985



1995



*These figures represent capacity by fuel type systemwide.

cogeneration project achieves a higher efficiency than pre-PURPA gas-fired generation.

The Texas PUC has attempted to leave fuel choice decisions with the utility companies. Under this policy, utility companies can pay a higher price to a cogenerator who offers fuel diversity as long as the cost does not exceed the utility's avoided cost. In addition, we have left with the utility the ability to choose between potential cogenerators on the basis of relative stability of their fuel sources.

Recently, there has been the suggestion that the PUC should establish a preference for use of Texas fuel resources. As suggested, a Texas utility should buy from cogenerators who use Texas-based gas or the PUC should favor new generating plants that will use Texas lignite versus western coal. While such a preference has yet to be reflected in PUC rules, the interest will obviously increase as long as the Texas oil and gas industry remains depressed. At the same time, on a plant-specific basis, there are several groups of local citizens opposing specific lignite mines who argue that it is a short-sighted environmental policy for utility companies to strip mine Texas lignite when western coal is available.

The PUC cogeneration rules proposed in 1984 did contain two preferences. The first was for municipal solid waste and renewable sources and the second was for cogeneration from solid fuels. The solid preference was dropped in 1985 because the Commission felt that it created an artificial preference that would not lead to the most competitive market for negotiation. Once again, it is obvious that benefits to ratepayers and jobs being the top two priorities influences a question like a solid fuel preference. The municipal solid waste and renewable source preference remains, in large part because of the small size of those projects and the fact that they have little hope of economically competing with large-scale industrially-based cogeneration projects without a preference. Their preference also shows that the concern for resource efficiency and the environmental aspects of energy policy questions still remain, even if they are no longer dominant.

Is the Competitive Market Setting the Price Efficiently in Texas?

This question concerns the role of the three parties in a competitive market with regulatory oversight: the utility company, the cogenerator, and the regulator. In the past, the most common complaint was that utility companies were not negotiating in good faith. This was the subject of numerous complaint dockets before the Public Utility Commission in the period from 1980 until 1984 when the new rules were put into effect. It was this atmosphere of impasse and bitterness between the utilities and the cogenerators that, in large part, led to the new set of rules. The new rules required the utility companies to buy cogeneration but not at prices above their avoided cost and not in quantities more than they needed. The new rules required standby, backup, and maintenance power and also required utility companies to wheel cogenerated power if they were not able to use it.

Having adopted rules that forced the utilities to the table and eliminated most of their ability to stall, the opposite question then becomes important, namely, "Has the PUC left sufficient discretion with the utilities to allow them to be effective negotiators?"

It was the PUC's intent to allow the utility company to pick their business partners. This was important coming out of a time of bitter complaint dockets because it also required the industrials to moderate some of their aggressive behavior. It was also our intent to allow the utility companies to select fuel type and to differentiate between cogenerators on the basis of which company had the best fuel contract; best, in this case, could be defined in terms of price, duration, availability of backup sources, likelihood of curtailment, and track record for honoring contracts.

The basic assumption in setting an avoided cost cap is that the cogenerator's power is of equal quality to a utility company's power. In reality, this becomes a point of negotiation in the contract because the utility can differentiate between cogenerators in a buyer's market on the basis of proven reliability and the extent of dispatchability of the power that is offered by the cogenerator. In addition, it was the PUC's intent to leave with the utility the ability to negotiate on questions of price, duration of the contract, and other contract terms. Some of the more important "other" terms have included the ability to control output by the cogenerator during peak periods (the ability to require a cogenerator to back down power) and the ability of the utility to take over a cogeneration plant should the cogenerator no longer be able to operate it.

The last aspect of whether or not the competitive market is setting prices efficiently concerns the PUC itself. The question here is whether or not PUC rules are themselves affecting market prices. Of most obvious concern is the complex and adversarial nature of PUC proceedings. Cogenerators have found that the ability and willingness to file a complaint with the PUC is often an essential element of getting to the bargaining table as an equal player. While the necessity of all sides to be well-represented is not out of place in a highly competitive market, it also works to exclude smaller, less sophisticated, and more casual players.

A second concern is the PUC approach to affiliate transactions. Like most state regulators, the Texas PUC has a set of strict tests for transactions between utility companies and their affiliates. Early in the process, several of the Texas utility companies either established or considered cogeneration affiliates. They soon found that PUC rules allowed no preference for affiliates and, in fact, probably created a greater burden than any advantage that might have been gained through a common organizational structure.

The last aspect of PUC procedures that might affect the competitive market is the regulatory requirement to review utility contracts. Regulated companies are accustomed to the fact that any contract they sign will eventually be subject to regulatory review. This regulatory review has, in the past few years especially with the nuclear plant cost overruns, become more intense and aggressive. As a consequence of regulators asserting their right of review, utilities often include in cogeneration contracts a regulatory escape clause. Such clauses nullify or modify the contract if the contract is not approved by the regulatory authority. While regulatory escape clauses are not uncommon in the utility business, they are foreign to cogenerators and especially their financial backers. Cogenerators in Texas have asserted that regulatory escape clauses are limiting their ability to gain financing, but as of yet there is no firm proof of that point, and the question has not become critical because an oversupply of cogeneration still remains. Whereas, limiting the ability of a regulator to review a cogeneration contract would ease the minds of the nonregulated participants, such a limitation on regulatory oversight goes against the stream of current regulatory practice. This is an example of the inevitable friction when nonregulated industries seek to participate in a regulated market and is an area where regulators and the nonregulator participants will both have to give up a little.

The last aspect of whether or not the competitive market is setting prices efficiently in Texas concerns barriers that might limit the action of the competitive market. The most obvious is the availability of transmission. The transmission systems in Texas were designed for reliability; they were not principally designed to carry large amounts of bulk power. At the same time, for cogeneration to reach its true economic potential in Texas, a more extensive transmission system must be established. PUC rules require utility companies to wheel cogenerated power if they do not purchase the power. If transmission facilities are necessary for wheeling, the utility company must build those facilities, but they will be reimbursed by the cogenerator. The major economic question then is the rate for wheeling power. Setting wheeling rates is a balancing act between making the movement of cogenerated power economical and not requiring ratepayers to subsidize cogenerators. Current Texas wheeling rates are a compromise between the rates advocated by the utilities and those advocated by the cogenerators. It is too early to tell whether or not the rates established are economically efficient, but we do have over 500 MW of cogenerated power moving from the Gulf Coast to North Texas under those rates.

The other key transmission question concerns the link between our intrastate ERCOT transmission system and the FERC regulated transmission systems that surround it. The questions here are jurisdictional and technical. Texas remains opposed to federal regulation of our intrastate transmission system, but we are willing to seek ways to more efficiently move bulk power between the intra and interstate systems.

Are the Current Limits on Cogenerators Still in the Public Interest?

The most obvious legal limitation on the development of cogeneration is the restriction on utility ownership. I am sure this federal restriction will be hotly contested and is likely an issue that would be debated within our own Commission. Personally, I do not oppose removal of the restriction as a means to eliminate an artificial barrier standing in the way of full economic development of cogneration potential. The regulatory problems that inevitably would arise from active utility participation in cogeneration can be solved as we go and, from the viewpoint of cogeneration in Texas, do not warrant the continuation of the limitation. For a state where cogenerators are primarily small and the industry is in its infancy, I can understand how one might take a different view. As a compromise, one might advocate allowing the decision to be made on a state-by-state basis.

The second limit concerns the federal prohibition of new gas-fired baseload generation. This question clearly goes back to the list of priorities discussed earlier. If national security and resource efficiency are the most important concerns, then the prohibition should continue. If, as we believe in Texas, the current top priority is economic benefit to ratepayers and the creation and preservation of jobs, then this artificial barrier should not remain. I am not convinced that removal of the barrier will create a tremendous surge in new gas-fired baseload generation if utilities are required at the same time by their state-level regulators to pursue least-cost generation plans. If cogeneration with true fuel efficiencies is available, it can economically beat the price of gas-fired baseload generation. At the same time, the removal of this artificial barrier would limit the development of cogenerators who enter the market based upon loopholes and limitations in the law rather than on true energy efficiency.

At the state level in Texas, we have created a limitation against retail sales by cogenerators without a certificate of convenience and necessity from the Commission. In reality, this means we stand in the way of retail sales by cogenerators. In addition, we have created a prohibition against wheeling between cogenerators. In the most obvious example, an industrial with two geographically separate sites is not allowed to cogenerate at one and transport the power to the other. Both the limitation on retail sales by cogenerators and the limitation on wheeling between cogenerators goes against the idea of maximum economic development of the cogeneration potential in Texas. But, at the same time, we believe that removal of these limitations would mean the loss of the industrial base for several of our utility companies. For example, Houston Lighting & Power has an industrial load of roughly 50%. At a time when we are working to assimilate four nuclear plants, the loss of the industrial base in Texas would mean higher rates for those electric customers who do not have a choice. It is only fair to point out the due to high energy prices argument on the other side which states that such an artificial barrier will only mean self generation on the part of the industrials or the loss of jobs because of high energy prices. Fortunately, because fuel prices are on their way down in Texas along with utility rates in general, the loss of jobs due to high energy prices argument has not become critical yet. On the other hand, lower natural gas prices do make the possibility the self generation more appealing to some industrials.

Does Current Cogeneration Policy in Texas Have Unintended Side Effects?

The foregoing questions cause one to wonder about the side effects of the cogeneration policy as established by the Public Utility Commission in Texas. From the discussion on fuels, one has to admit that cogeneration could well delay the move in Texas to solid fuels and the full development of Texas lignite. As I have discussed, this question is really a matter of priorities, and economic benefit weighs toward cogeneration.

A more subtle side effect concerns risk and quality of service. If cogeneration means increased dependence on natural gas, then that in turn means dependence on a more volatile fuel in terms of price, assured supply, and potential for governmental intervention. In addition, greater use of cogeneration means more players, and adds a group of companies who are not bound by the traditional public utility culture. I do not mean to speak abstractly here, but a culture does exist in the public utility industry which takes for granted the obligation to serve no matter what the circumstance. Whether such a blind obligation is economically efficient and is sustainable in the future is a question we can debate at a later time. But, where cogenerators might contractually obligate themselves to a similar obligation to serve no matter what the circumstance, one cannot help but feel that the culture in a competitive industry holds just as dearly the right to go in and out of business should circumstances necessitate.

The fact that cogeneration adds risk to the electric utility system can be contractually limited but will remain with us until we have enough experience to know whether or not cogenerators will honor their contracts when times get tough. It is this added element of risk that cogneration brings that caused the Public Utility Commission in Texas to abandon the concept espoused by PURPA that cogeneration should be priced with a neutral effect on ratepayers. We believe that cogeneration, while it has economic benefits for Texas, also introduces greater risks, and therefore ratepayers must receive a share of the benefits in the form of lower rates.

A more theoretical long-term side effect of cogeneration is the instability it will inevitably introduce into the electric utility industry. Previously, the barriers to entry and exit from the business of generating electrical power were technical and scale. Now, the technology of generating electricity is no longer closely held and generation facilities are available in small sizes. That means that the barriers to full competition within the electric utility industry are no longer technical but are now paper barriers. Words on paper can be changed with every legislative session and with every rulemaking proceeding by a regulatory body. It is interesting to note that a technical background is no longer as essential for success in the electric utility industry whereas one might argue that experience with the regulatory and legislative process is now the core technology.

The last concern is whether the current policy for cogeneration in Texas will underdevelop the cogeneration potential. Present policy is oriented towards large projects and sophisticated players. We have created and hope to maintain a competitive market. Our system is not designed for large numbers of small projects or casual participants. The question then is whether or not our current approach will undershoot the full economic potential that cogeneration could have for Texas. This is a question that has not been important in the past, but I believe will begin to be important in the future as we assimilate most of the large projects and begin to see larger numbers of smaller projects.

What Does the Future Hold for Cogeneration in Texas?

From my view, it appears we are approaching a third phase for cogeneration in Texas. Things have been relatively peaceful for the past two years and we have been able to get a number of the large projects under capacity contract. But, we are reaching the point where we have deferred most of the projects that the utility companies are willing to give up easily, when considered in the context of their goals for fuel diversification and their own plans for capital investment. Recent events would indicate that the cogenerators and utilities are preparing for a new battle in the upcoming legislative session oriented towards removing the barrier on retail sales, wheeling between cogenerators, and stricter economic tests for proposed utility generation. The best example of this brewing battle is the cogenerator attack on nuclear plant economics, a subject on which they have been silent in the past.

A second trend in the future is to move toward greater self generation on the part of industry. Lower natural gas prices and the developments in small package units, growing out of technological developments in the turbine industry, makes self generation both economically and technically feasible. For an industrial customer, the cost comparison is between the regulated rate and what they can buy gas and generate for on their own. Whereas utility rates in Texas have been stable or gone down for the past two or three years, the four nuclear plants remain a question. Some industrial customers will attempt to lock in long-term gas contracts and will move to self generation as a hedge against uncertainty in the future when the nuclear plants are brought into rate base. One can easily see how this trend could create a spiral as loss of industrial customers cause remaining rates to go up, which in turn drives more industrial customers off the system.

From a regulatory standpoint, this trend causes two responses. The first is to see that industrial rates are cost-based and that the nuclear plants are brought into rate base in such a way as to avoid a rate shock. The second response is to reconsider the absolute obligation to serve that a utility company assumes with a certificate of convenience and necessity. In other words, if a utility company builds to meet the needs of an industrial customer, and that industrial customer chooses to become a self generator, should the utility company be required to maintain that capacity to the detriment of the remaining ratepayers, on the off chance that the industrial customer might choose to rejoin the system.

The trend toward self generation will also cause responses by the more aggressive utility companies. Some will seek pricing plans, which encourage the industrials to remain on system, and others will, of necessity, devise fuel and capacity payments that recognize the fact that many industrial customers have self generation and cogneration options.

Another generation trend arises from the fact that the technology of electrical generation is now more diffuse. Specifically, new utility generation capacity may not be built by utility companies. We have a proposed project in Texas which is to be built and financed by the construction company and the manufacturer of the generator and will be turned over to the utility company at a guaranteed turnkey price. With a continuation of the limitation on utility participation in cogeneration projects, this trend will concern generation only. If the limitation is removed, I would expect this trend to intensify and more of the projects to be cogeneration in design.

The last trend I see for Texas is a move toward smaller projects. We have filled much of the immediate need for generating capacity with cogeneration projects in large chunks. While we probably have several 200-400 MW projects that remain to be built or put under capacity contract, I expect that in the future, we will move to smaller projects. The smaller projects will allow utilities to better match capacity needs with available cogenerators without incurring regulatory problems because of excess generating capacity. Because technology and low natural gas prices have removed some of the economies of scale, the small projects can compete in price.

CONCLUSION

I hope that from my comments you have come to the conclusion that the Texas PUC was faced with conflicting priorities in 1984 when we established the set of rules creating the current environment for cogeneration in Texas. We had tremendous cogeneration potential, but had made little progress other than accumulating huge legal fees in the preceding four years. The situation required that we decide on priorities and then establish a pricing system that could achieve those goals. As an interim conclusion, I am pleased with the success we have had, but it will be some time before more neutral observers will be able to determine if we made the correct economic decisions. We have broken the logjam and now have 1,500 MW of cogeneration under long-term capacity contract with another 1,500 MW within easy reach. I expect that during the next 10 years cogeneration will comprise 10-15% of the generating capacity in Texas. I believe that cogeneration brings added risk to the generation system in Texas, but that ratepayers will be adequately compensated through lower rates.

Let me end by once again discussing the time frame. Texas is one of the last states to go through assimilation of nuclear plants into rate base. Our experience will be similar to the states that have gone before us, and hopefully we will learn through their experiences. But, in any case, it is a time of uncertainty and some Texas companies are rated lower by Wall Street than their financial performance would warrant because of the uncertainty of nuclear construction and nuclear regulatory treatment. Several Texas companies have enormous nuclear investments to absorb when compared to their previous investment levels.

We are counting on cogeneration to buy us 8-12 years. That tends to be the duration of low-cost natural gas contracts, and it roughly corresponds to the amount of time we will need to level the effects of the nuclear plants. The 8-12 year window of cogeneration gives us time to determine what the true cost of fossil fuel generation will be, in light of the acid rain debate. The window will allow Texas companies to use cogeneration instead of going to Wall Street to finance their own generation plants, and will give us a better idea of the future of natural gas supply and price.

Obviously, we do not have a full 8-12 years since it takes at least five years to build a fossil fuel plant. But, cogeneration will provide a welcome opportunity to better understand future electrical consumption demands in Texas especially as it relates to the future of the petrochemical and refining industries.

While there are improvements we believe could be made in PURPA, and while we advocate the abolition of the Fuels Use Act and call for a national energy policy that recognizes the importance of a strong domestic oil and gas industry; PURPA has accomplished much of what was intended as it relates to cogeneration in Texas.

APPENDIX A

CURRENT AND PROJECTED COGENERATION AND SMALL POWER PRODUCTION IN TEXAS

As of May 1986

UTILITY AVOIDED COST COMPARISON
MAXIMUM CAPACITY AND ENERGY PAYMENTS FOR FIRM POWER CONTRACTS

	CP&L COLETO CREEK 2		EPEC PURCHASED POWER		GSU NELSON 5		HL&P MALAKOFF	
YEAR	CAPACITY PAYMENT $/KW/YR	ENERGY PAYMENT C/KWH	CAPACITY PAYMENT $/KW/YR	ENERGY PAYMENT C/KWH	CAPACITY PAYMENT $/KW/YR	ENERGY PAYMENT C/KWH	CAPACITY PAYMENT $/KW/YR	ENERGY PAYMENT C/KWH
1986	$0.00	0.00	$0.00	0.00	$0.00	0.00	$141.36	2.78
1987	$0.00	0.00	$0.00	0.00	$0.00	0.00	$150.12	2.97
1988	$0.00	0.00	$0.00	0.00	$0.00	0.00	$159.48	3.19
1989	$0.00	0.00	$0.00	0.00	$0.00	0.00	$169.44	3.41
1990	$0.00	0.00	$0.00	0.00	$0.00	0.00	$179.88	3.66
1991	$0.00	0.00	$0.00	0.00	$0.00	0.00	$191.16	3.90
1992	$0.00	0.00	$0.00	0.00	$0.00	0.00	$203.04	4.15
1993	$0.00	0.00	$0.00	0.00	$0.00	0.00	$215.64	4.43
1994	$0.00	0.00	$0.00	0.00	$0.00	0.00	$228.96	4.71
1995	$106.37	3.90	$0.00	0.00	$0.00	0.00		
1996	$112.98	4.10	192.36	4.28	$218.05	5.44		

UTILITY AVOIDED COST COMPARISON
MAXIMUM CAPACITY AND ENERGY PAYMENTS FOR FIRM POWER CONTRACTS

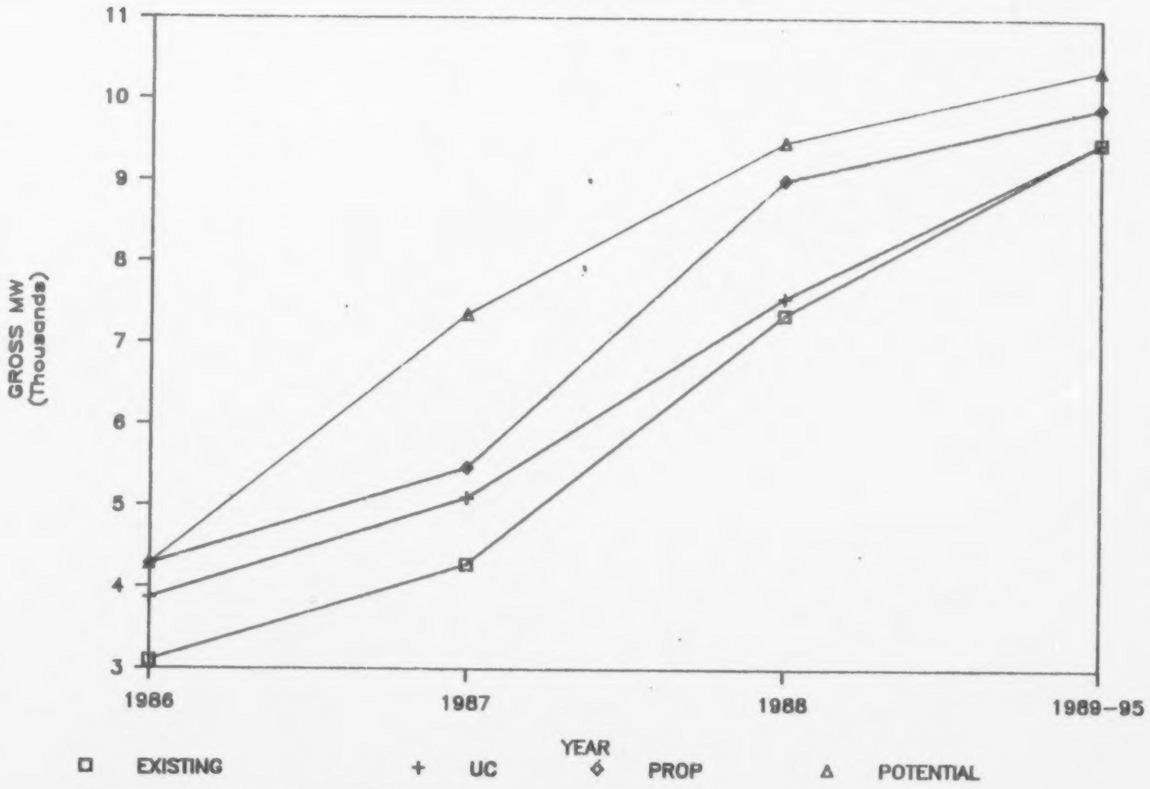
	LCRA LIGNITE		SPS SOUTH PLAINS 1		SWEPCO COLETO CREEK 2		TNP ROBERTSON COUNTY	
YEAR	CAPACITY PAYMENT $/KW/YR	ENERGY PAYMENT C/KWH	CAPACITY PAYMENT $/KW/YR	ENERGY PAYMENT C/KWH	CAPACITY PAYMENT $/KW/YR	ENERGY PAYMENT C/KWH	CAPACITY PAYMENT $/KW/YR	ENERGY PAYMENT C/KWH
1986	$0.00	0.00	$0.00	0.00	$0.00	0.00	$116.25	2.16
1987	$0.00	0.00	$0.00	0.00	$0.00	0.00	$123.22	2.24
1988	$0.00	0.00	$0.00	0.00	$0.00	0.00	$130.61	2.33
1989	$0.00	0.00	$0.00	0.00	$0.00	0.00	$138.45	2.43
1990	$0.00	0.00	$0.00	0.00	$0.00	0.00	$146.76	2.52
1991	$123.48	1.67	$0.00	0.00	$0.00	0.00	$155.56	2.63
1992	$132.25	1.78	$20.71	6.14	$0.00	0.00	$164.90	2.71
1993	$141.90	1.91	$44.81	6.26	$0.00	0.00	$174.79	2.69
1994	$151.84	2.04	$42.43	6.58	$0.00	0.00	$185.28	2.78
1995	$162.31	2.18	$47.11	7.08	$109.54	3.90	$196.40	2.88
1996			38.55	7.60	116.35	4.10		

UTILITY AVOIDED COST COMPARISON
MAXIMUM CAPACITY AND ENERGY PAYMENTS FOR FIRM POWER CONTRACTS

	TUEC FOREST GROVE 1		WTU COLETO CREEK 2	
YEAR	CAPACITY PAYMENT $/KW/YR	ENERGY PAYMENT C/KWH	CAPACITY PAYMENT $/KW/YR	ENERGY PAYMENT C/KWH
1986	$0.00	0.00	$0.00	0.00
1987	$0.00	0.00	$0.00	0.00
1988	$0.00	0.00	$0.00	0.00
1989	$154.29	2.30	$0.00	0.00
1990	$165.20	2.41	$0.00	0.00
1991	$176.88	2.53	$0.00	0.00
1992	$189.38	2.66	$0.00	0.00
1993	$202.77	2.79	$0.00	0.00
1994	$217.11	2.93	$106.77	3.72
1995	$232.46	3.08	$113.40	3.91
1996				

COGENERATION IN TEXAS

Megawatts by Year and Status (Certainty) Shown Cumulatively



Source: Public Utility Commission of Texas, May 1986

PUBLIC UTILITY COMMISSION OF TEXAS

COGENERATION AND SMALL POWER PRODUCTION DATA BASE
EXISTING, PROPOSED AND POTENTIAL PROJECTS

COGENERATOR/SPP	LOCATION	UTILITY SERVICE AREA	PRIMARY FUEL	GROSS MW	PROJECT STATUS	ON LINE DATE
MITCHELL ENERGY CORP.	BRIDGEPORT	TUEC	WG	3	EXIST	1986
PHILLIPS PETROLEUM	ORANGE	GSU	NG	10	EXIST	1986
AIRCO/VENTURE COGENERATION	PORT LAVACA	CP&L	WH	7	EXIST	1986
CROWN CENTRAL	SHIP CHANNEL	HL&P	WH	5	EXIST	1986
ENERGY ADVANCEMENT INC.	SEALY	HL&P	MSW	2	EXIST	1986
AIR PRODUCTS	PASADENA	HL&P	NG	4	EXIST	1986
UNCLE BEN'S		HL&P	BIO	1	EXIST	1986
DOW CHEMICAL	FREEPORT	HL&P	NG	1,300	EXIST	1986
IMPERIAL SUGAR	SUGARLAND	HL&P	NG	5	EXIST	1986
OSBORNE SOLAR	PAMPA	SPS	WI	0	EXIST	1986
STAUFFER CHEMICAL	BAYTOWN	HL&P	WH	1	EXIST	1986
POWER SYSTEMS	PORT ARTHUR	GSU	WH	7	EXIST	1986
CAPITOL COGEN./CELANESE	CLEAR LAKE	HL&P	NG	375	EXIST	1986
PHILLIPS	BORGER	SPS	WG	30	EXIST	1986
NASA WINDFARM	FREEPORT	HL&P	WI	1	EXIST	1986
IOWA BEEF PROCESSORS	AMARILLO	SPS	COAL	1	EXIST	1986
TEXASGULF CHEMICALS	NEWGULF	HL&P	NG	75	EXIST	1986
CELANESE CZ-1	PAMPA	SPS	WG	10	EXIST	1986
OTHER SELF-GEN. NON-QFS	VARIOUS	CP&L	NG	140	EXIST	1986
SW GT. PLAINTS RESEARCH	AMARILLO	SPS	WG	0	EXIST	1986
BAYOU/BIG THREE/GE	PASADENA	HL&P	NG	300	EXIST	1986
CELANESE CZ-2	PAMPA	SPS	CO	29	EXIST	1986
STAUFFER CHEMICAL	MANCHESTER	HL&P	WH	7	EXIST	1986
AMOCO PROD. SLAUGHTER FIELD	HOCKLEY CO.	SPS	NG	18	EXIST	1986
ENTERPRISE	MONT BELVIEW	HL&P	WH	5	EXIST	1986
HUBER	BORGER	SPS	WG	17	EXIST	1986
STANDARD OIL CHEMICALS	PORT LAVACA	CP&L	WH	13	EXIST	1986
MISC. WIND < 100 KW	VARIOUS	SPS	WI	0	EXIST	1986
COASTAL STATES PETRO CO.	CORPUS CHRISTI	CP&L	NG	47	EXIST	1986
SNIDER INDUSTRIES	MARSHALL	SWEPCO	BIO	3	EXIST	1986
ASARCO	EL PASO	EPEC	NG	10	EXIST	1986
LONE STAR STEEL	LONE STAR	SWEPCO	NG/WH	34	EXIST	1986
AMOCO CHEMICALS	CHOCOLATE BAYOU	HL&P	NG	37	EXIST	1986
AMOCO OIL	TEXAS CITY	TNP	NG	180	EXIST	1986
VALERO REFINING	CORPUS CHRISTI	CP&L	WH	64	EXIST	1986
AMOCO CHEMICALS	TEXAS CITY	TNP	NG	37	EXIST	1986
MEDICAL CENTER DEL ORO	HOUSTON	HL&P	NG	1	EXIST	1986
DIAMOND SHAMROCK	LA PORTE	HL&P	NG	230	EXIST	1986
PETRO-TEX (EXISTING)	DEEPWATER	HL&P	NG	70	EXIST	1986
UNION CARBIDE (OLD)	TEXAS CITY	TNP	NG	25	EXIST	1986
		TOTAL EXISTING:		3,105		

PUBLIC UTILITY COMMISSION OF TEXAS

COGENERATION AND SMALL POWER PRODUCTION DATA BASE
EXISTING, PROPOSED AND POTENTIAL PROJECTS

COGENERATOR/SPP	LOCATION	UTILITY SERVICE AREA	PRIMARY FUEL	GROSS MW	PROJECT STATUS	ON LINE DATE
PANDA ENERGY CORP.	MASTERSON	SPS	WI	40	CONSTR	1986
AES-DEEPWATER/ARCO PET.	SHIP CHANNEL	HL&P	PC	154	CONSTR	1986
TEMPLE-EASTEX INC.	EVADALE	GSU	BIO	9	CONSTR	1986
GOODYEAR	BEAUMONT	GSU	NG	15	CONSTR	1986
COGEN LYONDELL/PWR SYSTEM	SHIP CHANNEL	HL&P	NG	465	CONSTR	1986
DIAMOND SHAMROCK	DEER PARK	HL&P	NG	75	CONSTR	1986
PHELPS DODGE	EL PASO	EPEC	NG	9	CONSTR	1986
DUPONT/SABINE	ORANGE	GSU	NG	75	CONSTR	1987
ENERGY ADVANCEMENT INC.	WEST COLUMBIA	TNP	MSW	5	CONSTR	1987
UNION CARBIDE/NO 1 COGEN	TEXAS CITY	TNP	NG	441	CONSTR	1987
VALLEY VIEW ENERGY CORP.	GRUVER	SPS	BIO	52	CONSTR	1987
WICH. FALLS EN/CERTAINTEED	WICHITA FALLS	TUEC	NG	80	CONSTR	1987
DUPONT	VICTORIA	CP&L	NG	75	CONSTR	1987
CHEVRON CHEMICAL	ORANGE	GSU	NG	38	CONSTR	1987
VALLEY VIEW ENERGY CORP.	HEREFORD	SPS	BIO	52	CONSTR	1987
TEMPLE-EASTEX	DIBOLL	TUEC	NG	214	CONSTR	1988
	TOTAL UNDER CONSTRUCTION:			1,799		
STANDARD OIL CHEMICALS	PORT LAVACA	CP&L	WH	4	PROP	1986
CHAMPION INT.	CORRIGAN	GSU	BIO	8	PROP	1986
RICE UNIVERSITY	HOUSTON	HL&P	NG	3	PROP	1986
MAXWELL HOUSE/GENERAL FOODS	HOUSTON	HL&P	NG	10	PROP	1986
ST. REGIS PAPER		HL&P	NG	68	PROP	1986
TEXACO CHEMICAL CO.	PORT ARTHUR	GSU	NG	100	PROP	1986
GULF OIL	PORT ARTHUR	GSU	NG	8	PROP	1986
LUBRIZOL/POWER SYSTEMS		HL&P	NG	64	PROP	1986
ARCO CHEMICAL	CHOCOLATE BAYOU	HL&P	NG	75	PROP	1986
ARCO CHEMICAL		HL&P	NG	75	PROP	1986
TEXAS INDUSTRIES INC.	MIDLOTHIAN	TUEC	COAL	100	PROP	1987
OWENS/ILLINOIS	ORANGE	GSU	BIO/NG	45	PROP	1987
TENNECO BUILDING	HOUSTON	HL&P		2	PROP	1987
PRIDE OIL	ABILENE	WTU	NG	50	PROP	1987
DUPONT	CORPUS CHRISTI	CP&L	NG	150	PROP	1987
GOODRICH	SHIP CHANNEL	HL&P	NG	19	PROP	1987
RHONE-POULENC INC./DECKER	FREEPORT	HL&P	NG	3	PROP	1987
EXXON CHEMICALS	BAYTOWN	HL&P	NG	225	PROP	1988
TEXAS INSTRUMENTS	DALLAS	TUEC	NG	200	PROP	1988
TEXACO REFINING MRKTNG	PORT ARTHUR	GSU	NG	164	PROP	1988

PUBLIC UTILITY COMMISSION OF TEXAS

COGENERATION AND SMALL POWER PRODUCTION DATA BASE
EXISTING, PROPOSED AND POTENTIAL PROJECTS BY SERVICE AREA

COGENERATOR/SPP	LOCATION	UTILITY SERVICE AREA	PRIMARY FUEL	GROSS MW	PROJECT STATUS	ON LINE DATE
COASTAL STATES PETRO CO.	CORPUS CHRISTI	CP&L	NG	47	EXIST	1986
OTHER SELF-GEN. NON-QFS	VARIOUS	CP&L	NG	140	EXIST	1986
STANDARD OIL CHEMICALS	PORT LAVACA	CP&L	WH	13	EXIST	1986
AIRCO/VENTURE COGENERATION	PORT LAVACA	CP&L	WH	7	EXIST	1986
VALERO REFINING	CORPUS CHRISTI	CP&L	WH	64	EXIST	1986
STANDARD OIL CHEMICALS	PORT LAVACA	CP&L	WH	4	PROP	1986
DUPONT	VICTORIA	CP&L	NG	75	CONSTR	1987
DUPONT	CORPUS CHRISTI	CP&L	NG	150	PROP	1987
UNION CARBIDE	SEADRIFT	CP&L	NG	90	POTENT	1988
BISHOP COGEN. CO. CELANESE	BISHOP	CP&L	NG	201	POTENT	1988
BISHOP COGEN. CO. CELANESE	BISHOP	CP&L	NG	35	PROP	1988
ALCOA/INTERNORTH	POINT COMFORT	CP&L	NG	200	PROP	1988
				======		
		TOTAL CP&L:		1,026		
ASARCO	EL PASO	EPEC	NG	10	EXIST	1986
PHELPS DODGE	EL PASO	EPEC	NG	9	CONSTR	1986
				======		
		TOTAL EPEC:		19		
GOODYEAR	BEAUMONT	GSU	NG	15	CONSTR	1986
POWER SYSTEMS	PORT ARTHUR	GSU	WH	7	EXIST	1986
TEMPLE-EASTEX INC.	EVADALE	GSU	BIO	9	CONSTR	1986
CHAMPION INT.	CORRIGAN	GSU	BIO	8	PROP	1986
TEXACO CHEMICAL CO.	PORT ARTHUR	GSU	NG	100	PROP	1986
PHILLIPS PETROLEUM	ORANGE	GSU	NG	10	EXIST	1986
GULF OIL	PORT ARTHUR	GSU	NG	8	PROP	1986
CHEVRON CHEMICAL	ORANGE	GSU	NG	38	CONSTR	1987
DUPONT/SABINE	ORANGE	GSU	NG	75	CONSTR	1987
OWENS/ILLINOIS	ORANGE	GSU	BIO/NG	45	PROP	1987
TEXACO CHEMICAL	PORT NECHES	GSU	NG	38	POTENT	1988
TEXACO REFINING MRKTNG	PORT ARTHUR	GSU	NG	164	PROP	1988
OLIN CHEMICAL	BEAUMONT	GSU		3	PROP	1995
				======		
		TOTAL GSU:		520		
DIAMOND SHAMROCK	DEER PARK	HL&P	NG	75	CONSTR	1986
STAUFFER CHEMICAL	BAYTOWN	HL&P	WH	1	EXIST	1986
MAXWELL HOUSE/GENERAL FOODS	HOUSTON	HL&P	NG	10	PROP	1986

PUBLIC UTILITY COMMISSION OF TEXAS

COGENERATION AND SMALL POWER PRODUCTION DATA BASE
EXISTING, PROPOSED AND POTENTIAL PROJECTS BY SERVICE AREA

COGENERATOR/SPP	LOCATION	UTILITY SERVICE AREA	PRIMARY FUEL	GROSS MW	PROJECT STATUS	ON LINE DATE
PETRO-TEX	DEEPWATER	HL&P	NG	70	EXIST	1986
LUBRIZOL/POWER SYSTEMS		HL&P	NG	64	PROP	1986
IMPERIAL SUGAR	SUGARLAND	HL&P	NG	5	EXIST	1986
DIAMOND SHAMROCK	LA PORTE	HL&P	NG	230	EXIST	1986
ENTERPRISE	MONT BELVIEW	HL&P	WH	5	EXIST	1986
COGEN LYONDELL/PWR SYSTEM	SHIP CHANNEL	HL&P	NG	465	CONSTR	1986
UNCLE BEN'S		HL&P	BIO	1	EXIST	1986
MEDICAL CENTER DEL ORO	HOUSTON	HL&P	NG	1	EXIST	1986
AMOCO CHEMICALS	CHOCOLATE BAYOU	HL&P	NG	37	EXIST	1986
CROWN CENTRAL	SHIP CHANNEL	HL&P	WH	5	EXIST	1986
ENERGY ADVANCEMENT INC.	SEALY	HL&P	MSW	2	EXIST	1986
DOW CHEMICAL	FREEPORT	HL&P	NG	1,300	EXIST	1986
STAUFFER CHEMICAL	MANCHESTER	HL&P	WH	7	EXIST	1986
ARCO CHEMICAL		HL&P	NG	75	PROP	1986
AIR PRODUCTS	PASADENA	HL&P	NG	4	EXIST	1986
ST. REGIS PAPER		HL&P	NG	68	PROP	1986
ARCO CHEMICAL	CHOCOLATE BAYOU	HL&P	NG	75	PROP	1986
BAYOU/BIG THREE/GE	PASADENA	HL&P	NG	300	EXIST	1986
NASA WINDFARM	FREEPORT	HL&P	WI	1	EXIST	1986
CAPITOL COGEN./CELANESE	CLEAR LAKE	HL&P	NG	375	EXIST	1986
AES-DEEPWATER/ARCO PET.	SHIP CHANNEL	HL&P	PC	154	CONSTR	1986
RICE UNIVERSITY	HOUSTON	HL&P	NG	3	PROP	1986
TEXASGULF CHEMICALS	NEWGULF	HL&P	NG	75	EXIST	1986
GOODRICH	SHIP CHANNEL	HL&P	NG	19	PROP	1987
TENNECO BUILDING	HOUSTON	HL&P		2	PROP	1987
GOODYEAR/GE	DEEPWATER	HL&P	NG	350	POTENT	1987
TEX. RELATED ENERGY		HL&P	NG	100	POTENT	1987
GENTEX	BAYPORT	HL&P	NG	240	POTENT	1987
AMERICAN RECOVERY SYSTEMS		HL&P	BIO	10	POTENT	1987
GENTEX - ICI	BAYPORT	HL&P	NG	60	POTENT	1987
RHONE-POULENC INC./DECKER	FREEPORT	HL&P	NG	3	PROP	1987
AES-SIMS BAYOU/ARCO PET.	SHIP CHANNEL	HL&P	PC	165	POTENT	1987
MOBAY/GE	BAYTOWN	HL&P	NG	325	POTENT	1987
COGENLYNCHBURG/PWR.SYS/UP	LA PORTE	HL&P	NG	425	POTENT	1987
WASTE CONTROL SYSTEMS		HL&P	BIO	6	POTENT	1987
WARREN PETROLEUM CO.	MONT. BELVIEU	HL&P	NG	75	PROP	1988
AES-ADAMS TERMINAL	SHIP CHANNEL	HL&P	PC	150	PROP	1988
CHAMPION PAPER	DEEPWATER	HL&P	NG	190	PROP	1988
AM. REF FUEL/BR.FERRIS	PASADENA	HL&P	MSW	48	PROP	1988
PETRO-TEX	DEEPWATER	HL&P	NG	120	POTENT	1988
OLIN MOBIL	SHIP CHANNEL	HL&P		10	PROP	1988
EXXON CHEMICALS	BAYTOWN	HL&P	NG	225	PROP	1988

PUBLIC UTILITY COMMISSION OF TEXAS

COGENERATION AND SMALL POWER PRODUCTION DATA BASE
EXISTING, PROPOSED AND POTENTIAL PROJECTS

COGENERATOR/SPP	LOCATION	UTILITY SERVICE AREA	PRIMARY FUEL	GROSS MW	PROJECT STATUS	ON LINE DATE
AES-ADAMS TERMINAL	SHIP CHANNEL	HL&P	PC	150	PROP	1988
CHAMPION PAPER	DEEPWATER	HL&P	NG	190	PROP	1988
AM. REF FUEL/BR.FERRIS	PASADENA	HL&P	MSW	48	PROP	1988
WARREN PETROLEUM CO.	MONT. BELVIEU	HL&P	NG	75	PROP	1988
OLIN MOBIL	SHIP CHANNEL	HL&P		10	PROP	1988
PHILLIPS PETROLEUM	SWEENY	TNP	NG	150	PROP	1988
ALCOA/INTERNORTH	POINT COMFORT	CP&L	NG	200	PROP	1988
BISHOP COGEN. CO. CELANESE	BISHOP	CP&L	NG	35	PROP	1988
DIAMOND SHAMROCK	TEXAS PANHANDLE	SPS	BIO	200	PROP	1989
SOLTEX/EBASCO	SHIP CHANNEL	HL&P	NG	7	PROP	1990
OLIN CHEMICAL	BEAUMONT	GSU		3	PROP	1995
MOBIL		HL&P	NG	12	PROP	1995
COGEN KERN BLUFF	HOUSTON	HL&P	NG	45	PROP	1995
QUAKER OATS		HL&P		25	PROP	1995
GENTEX - TENNECO	HOUSTON	HL&P	NG	60	PROP	1995
AMERICAN RECOVERY SYSTEMS	LAPORTE	HL&P	NG	52	PROP	1995
TRETOLITE, INC.	PASADENA	HL&P	NG	1	PROP	1995
AMERICAN HOECHST		HL&P	NG	20	PROP	1995
ANCHOR HOCKING		HL&P	NG	4	PROP	1995
		TOTAL PROPOSED:		2,659		
WASTE CONTROL SYSTEMS		HL&P	BIO	6	POTENT	1987
AMERICAN RECOVERY SYSTEMS		HL&P	BIO	10	POTENT	1987
GENTEX - ICI	BAYPORT	HL&P	NG	60	POTENT	1987
COGENLYNCHBURG/PWR.SYS/UP	LA PORTE	HL&P	NG	425	POTENT	1987
AES-SIMS BAYOU/ARCO PET.	SHIP CHANNEL	HL&P	PC	165	POTENT	1987
GENTEX	BAYPORT	HL&P	NG	240	POTENT	1987
MOBAY/GE	BAYTOWN	HL&P	NG	325	POTENT	1987
TEX. RELATED ENERGY		HL&P	NG	100	POTENT	1987
TXO/DELHI/LA GLORIA REF.	TYLER	TUEC	NG	200	POTENT	1987
GOODYEAR/GE	DEEPWATER	HL&P	NG	350	POTENT	1987
UNION CARBIDE	SEADRIFT	CP&L	NG	90	POTENT	1988
MARATHON	TEXAS CITY	TNP	NG	15	POTENT	1988
PETRO-TEX (PROPOSED)	DEEPWATER	HL&P	NG	120	POTENT	1988
BISHOP COGEN. CO. CELANESE	BISHOP	CP&L	NG	201	POTENT	1988
TEXACO CHEMICAL	PORT NECHES	GSU	NG	38	POTENT	1988
TEXAS CITY REFINING/PWR. SY	TEXAS CITY	TNP	NG	37	POTENT	1995
MONSANTO/GENERAL ELECTRIC	TEXAS CITY	TNP	NG	425	POTENT	1995
		TOTAL POTENTIAL:		2,807		

PUBLIC UTILITY COMMISSION OF TEXAS

COGENERATION AND SMALL POWER PRODUCTION DATA BASE
EXISTING, PROPOSED AND POTENTIAL PROJECTS

```
                                                UTILITY
                                                SERVICE PRIMARY  GROSS  PROJECT ON LINE
              COGENERATOR/SPP        LOCATION      AREA    FUEL     MW   STATUS    DATE
========================================================================================
                                           STATUS TOTALS:
                                                   EXISTING      3,105
                                         UNDER CONSTRUCTION      1,799
                                                   PROPOSED      2,659
                                                               =======
                                                FIRM TOTAL:      7,563
                                                  POTENTIAL      2,807
                                                               =======
                                                     TOTAL:     10,370
                                             UNDER CONTRACT      1,420
                                                               =======
                                            TOTAL AVAILABLE      8,950
                                             FIRM AVAILABLE      6,143
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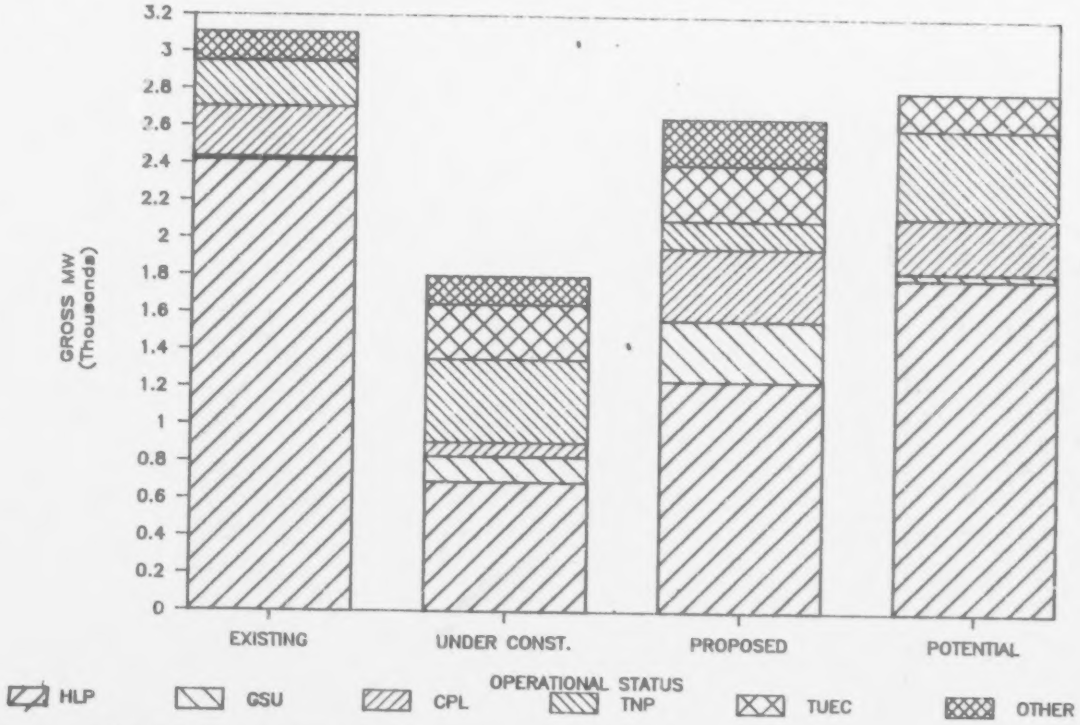
COGENERATION IN TEXAS

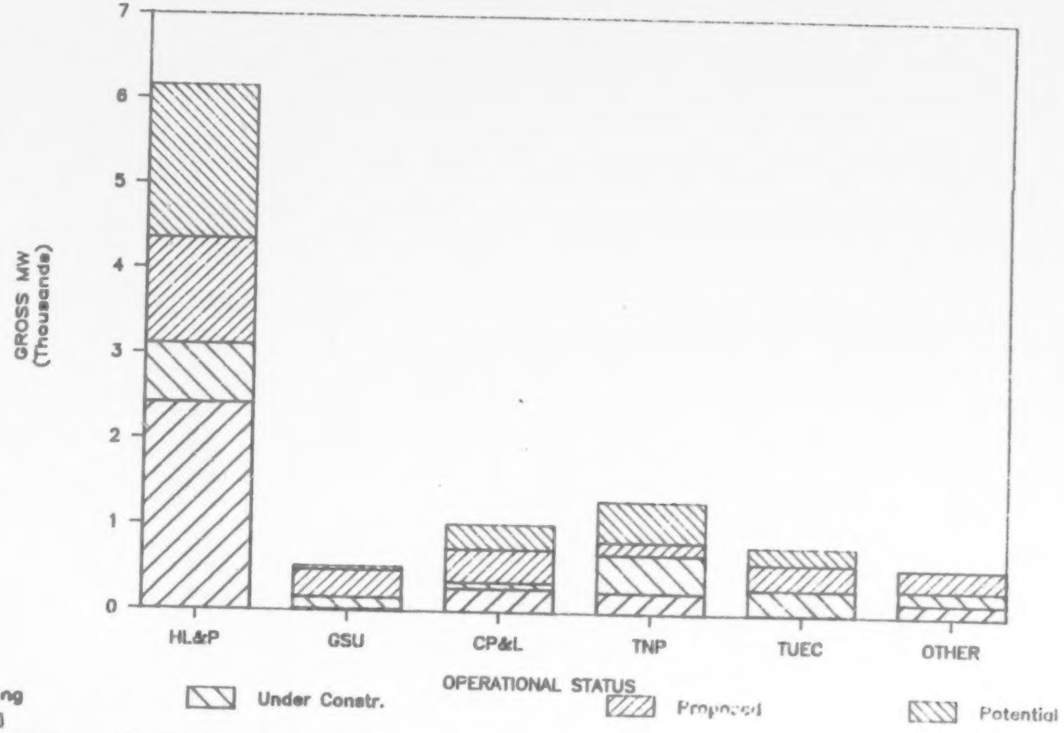
Megawatts by Status (Certainty) and Utility Service Area



Source: Public Utility Commission of Texas, May 1986

COGENERATION IN TEXAS

Megawatts by Utility Service Area and Status (Certainty)



Source: Public Utility Commission of Texas, May 1986

PUBLIC UTILITY COMMISSION OF TEXAS

COGENERATION AND SMALL POWER PRODUCTION DATA BASE
EXISTING, PROPOSED AND POTENTIAL PROJECTS BY SERVICE AREA

COGENERATOR/SPP	LOCATION	UTILITY SERVICE AREA	PRIMARY FUEL	GROSS MW	PROJECT STATUS	ON LINE DATE
SOLTEX/EBASCO	SHIP CHANNEL	HL&P	NG	7	PROP	1990
GENTEX - TENNECO	HOUSTON	HL&P	NG	60	PROP	1995
TRETOLITE, INC.	PASADENA	HL&P	NG	1	PROP	1995
AMERICAN HOECHST		HL&P	NG	20	PROP	1995
MOBIL		HL&P	NG	12	PROP	1995
ANCHOR HOCKING		HL&P	NG	4	PROP	1995
COGEN KERN BLUFF	HOUSTON	HL&P	NG	45	PROP	1995
AMERICAN RECOVERY SYSTEMS	LAPORTE	HL&P	NG	52	PROP	1995
QUAKER OATS		HL&P		25	PROP	1995
				======		
		TOTAL HL&P:		6,157		
AMOCO PROD. SLAUGHTER FIELD	HOCKLEY CO.	SPS	NG	18	EXIST	1986
CELANESE CZ-2	PAMPA	SPS	CO	29	EXIST	1986
SW GT. PLAINTS RESEARCH	AMARILLO	SPS	WG	0	EXIST	1986
HUBER	BORGER	SPS	WG	17	EXIST	1986
CELANESE CZ-1	PAMPA	SPS	WG	10	EXIST	1986
PHILLIPS	BORGER	SPS	WG	30	EXIST	1986
PANDA ENERGY CORP.	MASTERSON	SPS	WI	40	CONSTR	1986
OSBORNE SOLAR	PAMPA	SPS	WI	0	EXIST	1986
MISC. WIND < 100 KW	VARIOUS	SPS	WI	0	EXIST	1986
IOWA BEEF PROCESSORS	AMARILLO	SPS	COAL	1	EXIST	1986
VALLEY VIEW ENERGY CORP.	GRUVER	SPS	BIO	52	CONSTR	1987
VALLEY VIEW ENERGY CORP.	HEREFORD	SPS	BIO	52	CONSTR	1987
DIAMOND SHAMROCK	TEXAS PANHANDLE	SPS	BIO	200	PROP	1989
				======		
		TOTAL SPS:		450		
SNIDER INDUSTRIES	MARSHALL	SWEPCO	BIO	3	EXIST	1986
LONE STAR STEEL	LONE STAR	SWEPCO	NG/WH	34	EXIST	1986
				======		
		TOTAL SWEPCO:		37		
AMOCO OIL	TEXAS CITY	TNP	NG	180	EXIST	1986
UNION CARBIDE	TEXAS CITY	TNP	NG	25	EXIST	1986
AMOCO CHEMICALS	TEXAS CITY	TNP	NG	37	EXIST	1986
UNION CARBIDE/NO 1 COGEN	TEXAS CITY	TNP	NG	441	CONSTR	1987
ENERGY ADVANCEMENT INC.	WEST COLUMBIA	TNP	MSW	5	CONSTR	1987
PHILLIPS PETROLEUM	SWEENY	TNP	NG	150	PROP	1988

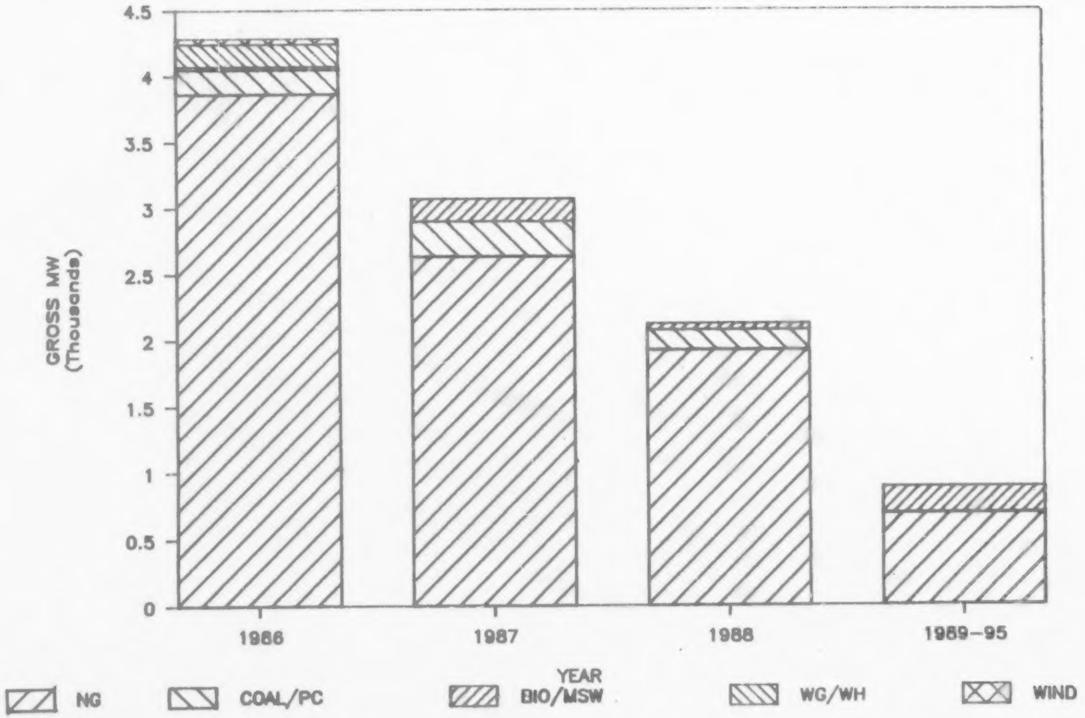
PUBLIC UTILITY COMMISSION OF TEXAS

COGENERATION AND SMALL POWER PRODUCTION DATA BASE
EXISTING, PROPOSED AND POTENTIAL PROJECTS BY SERVICE AREA

COGENERATOR/SPP	LOCATION	UTILITY SERVICE AREA	PRIMARY FUEL	GROSS MW	PROJECT STATUS	ON LINE DATE
MARATHON	TEXAS CITY	TNP	NG	15	POTENT	1988
MONSANTO/GENERAL ELECTRIC	TEXAS CITY	TNP	NG	425	POTENT	1995
TEXAS CITY REFINING/PWR. SY	TEXAS CITY	TNP	NG	37	POTENT	1995
		TOTAL TNP:		1,315		
MITCHELL ENERGY CORP.	BRIDGEPORT	TUEC	WG	3	EXIST	1986
WICH. FALLS EN/CERTAINTEED	WICHITA FALLS	TUEC	NG	80	CONSTR	1987
TEXAS INDUSTRIES INC.	MIDLOTHIAN	TUEC	COAL	100	PROP	1987
TXO/DELHI/LA GLORIA REF.	TYLER	TUEC	NG	200	POTENT	1987
TEMPLE-EASTEX	DIBOLL	TUEC	NG	214	CONSTR	1988
TEXAS INSTRUMENTS	DALLAS	TUEC	NG	200	PROP	1988
		TOTAL TUEC:		797		
PRIDE OIL	ABILENE	WTU	NG	50	PROP	1987
		TOTAL WTU:		50		

COGENERATION IN TEXAS

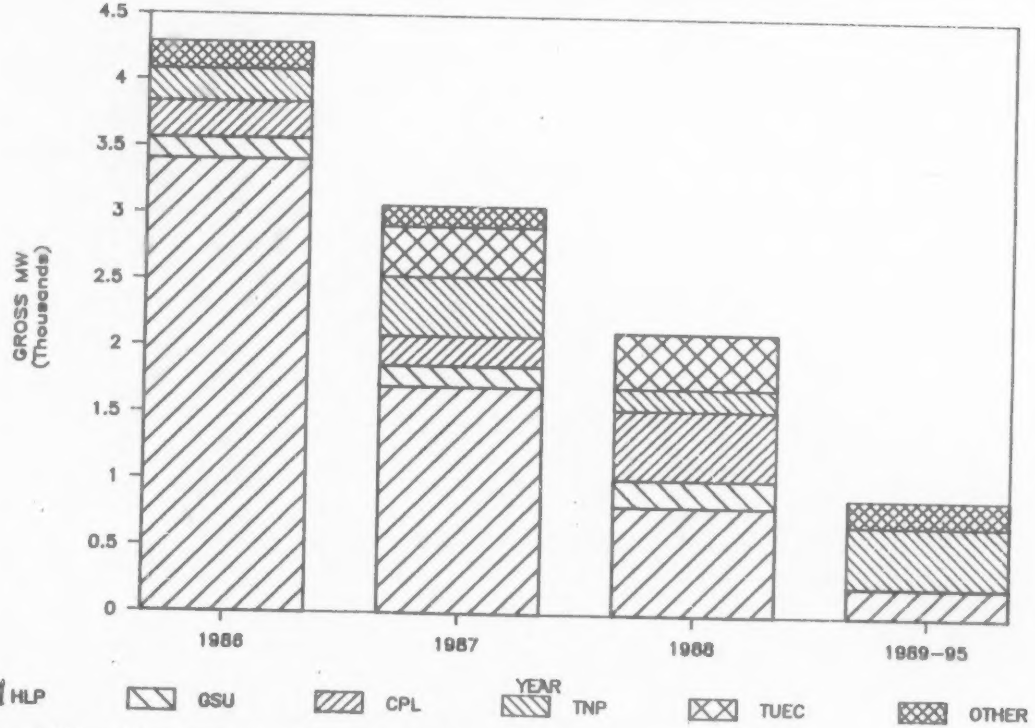
Megawatts by Year and Fuel



Source: Public Utility Commission of Texas, May 1986

COGENERATION IN TEXAS

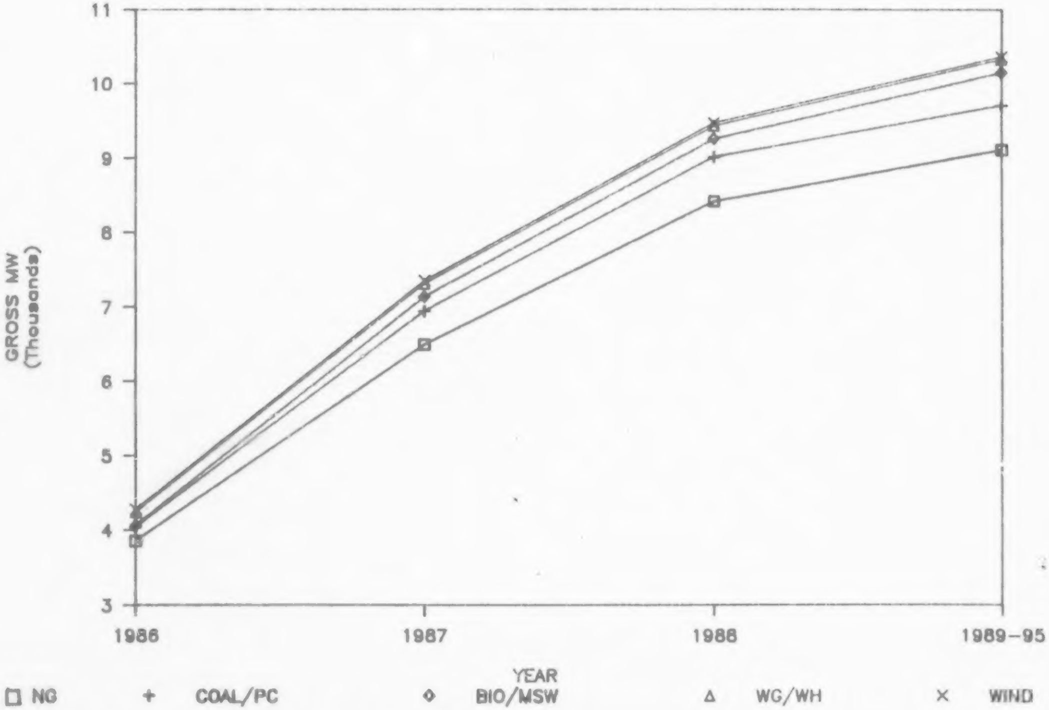
Megawatts by Year and Utility Service Area



Source: Public Utility Commission of Texas, May 1986

COGENERATION IN TEXAS

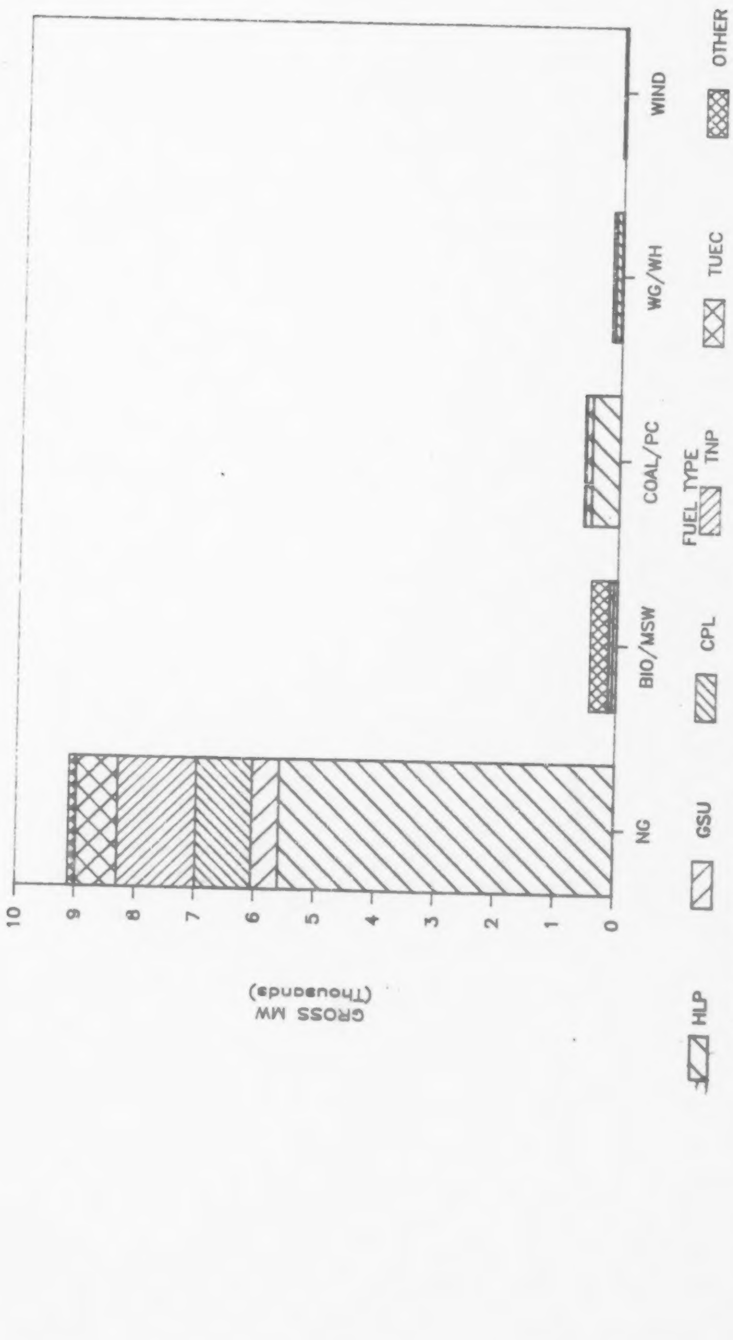
Megawatts by Year and Fuel Shown Cumulatively



Source: Public Utility Commission of Texas, May 1986

COGENERATION IN TEXAS

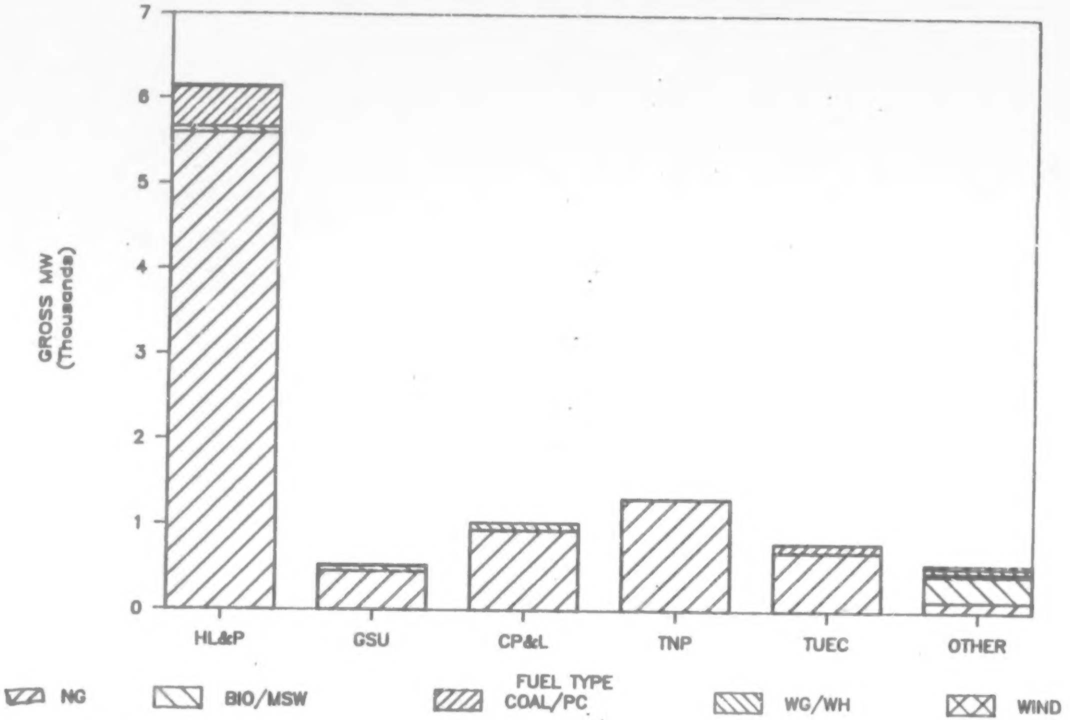
Megawatts by Fuel and Utility Service Area



Source: Public Utility Commission of Texas, May 1986

COGENERATION IN TEXAS

Megawatts by Utility Service Area and Fuel



Source: Public Utility Commission of Texas, May 1986

The Chairman. Thank you.
Mr. Wyse.

STATEMENT OF DUNCAN WYSE, DIRECTOR, POLICY AND PLANNING DIVISION, CALIFORNIA PUBLIC UTILITIES COMMISSION

Mr. Wyse. Thank you, Mr. Chairman. My name is Duncan Wyse. I am director of policy and planning at the California PUC.

It is a pleasure to report to you that PURPA as being implemented by the FERC and by State PUC's is successfully achieving its mandate, to encourage cogeneration and small power production. The success, perhaps, can be illustrated by California's history.

In 1980, the State's private utilities were considering construction of large and quite expensive baseload coal plants. Under PURPA, cogeneration and renewable resources have helped to defer construction of such plants, probably into the next century.

California, in 1980, was heavily dependent on natural gas and oil as its primary fuel. We were very concerned about that dependency. Under PURPA, renewable resources have displaced a good deal of oil and gas-fired generation, and the gas that we are burning is being burned more efficiently through cogeneration.

PURPA has helped us to diversify our resource mix and it has shown us that there is an alternative to utility generation that can come on line with the investors taking all the risks of construction costs, performance and the performance of the facility, itself.

We think there are really three virtues in the way the Federal Government has implemented PURPA. The first is, the act, itself. I think it was quite desirable to exempt from conventional regulation the category of facilities of small, renewable resources and cogeneration. These are resources that the utilities, themselves, are not necessarily the most adept at developing, either because of the small size or because it is part of another industrial process.

So we think that the act, itself, is very sound.

The second virtue of the Federal implementation was the avoided cost rule by the FERC. We think avoided cost pricing is the right principle. It draws out all economical alternatives to the utility generation, and over time, ratepayers benefit as the whole system becomes more efficient and we are able to turn down utility plants and avoid building new plants.

It also helps diversify the energy mix, itself.

The third virtue we think in the FERC implementation was the fact that they gave a lot of flexibility to the States. I think that is very important. States do have different capacity conditions, different resource needs. A State with overcapacity and low operating cost, baseload facilities, have very different needs than a State, for example, such as California, with high operating costs and some capacity needs.

In setting avoided costs, leaving the flexibility to set avoided cost at the State level, we can reflect both.

Turning to the California experience, we have aggressively implemented PURPA for several reasons, as mentioned earlier. We are dependent on oil and gas and we are very anxious to reduce that dependency. The large, baseload facilities are very expensive for various reasons, and we do, in California, are blessed with natural resources, be it thermal, biomass, wind, solar, as well as cogeneration.

Therefore, we did proceed to carefully adopt a set of standard offers that were designed based on avoided cost principles to encourage development of these resources. Without going into the details of those standard offers, I would stress that we have provided a variety of offers to meet the various needs and capabilities of the independent producers, ranging from our as-available offer, which varies much like a spot market price might vary, to longer term fixed price contracts for the renewable resources which have high capital costs and needs a price structure to attract financing.

We felt standard offers were important to create a fair negotiating position between the utilities and the independent producers. The standard offer contracts we have created are much like utility tariffs. All the terms and conditions are laid out so that it is a relative easy task to go to the utility and apply to provide energy to the utility.

The results of these standard offers have been spectacular. We have gone from 77 megawatts of on-line capacity, to 2,800 or so this year, and we have 15,000 megawatts under committed contracts in California. Not all those contracts are going to come on line, but some portion of them will.

As the percentage grows, we are seeing more diversity in the State, a good mix of resources that we have attracted with this program.

Contracts have been so successful that we have had to suspend them; the prices reflecting changing capacity needs given the amount of independent production coming on line has resulted in the Commission suspending the long term contracts. We now have to adjust them downward, the prices in those future contracts downward, to reflect the changing resource needs of the State.

Looking to the future, PURPA is fundamentally changing our electric system in California. We are more decentralized now. That has some advantages and has some disadvantages. The major advantage of independent production is that they do take all the risks. We don't have to deal with the kind of prudency reviews we were dealing with in some of the utility plants. Another advantage is the decentralization and diversification of resource.

The big issue and the concern we have now is, as this program grows, is integrating these producers into our system. As they grow, we have concerns about timing as they come on line, the versatility in how they are going to be able to respond to changing utility conditions.

The question really is, can a contract with an independent producer provide as much flexibility as the utility's own generation.

In our current proceedings, we are trying to address those questions and refine our contracts, make them more sophisticated to be more responsive to changing conditions.

We are going to certainly have more limits on the availability of these contracts, and essentially limit their availability to certain blocks of independent production. We are also going to try to build in more dispatchability options as we go forward. We are working on that now. I can't predict how it is going to come out, but we are.

Those are the kinds of things that we are dealing with.

So, to summarize, we think PURPA is working. We like the flexibility. It is a complicated area. We have spent a lot of time on it, but we do think the California ratepayers are benefiting and we are going to continue to work on it.

Thank you.

[The prepared statement of Mr. Wyse follows:]

Implementation of
The Public Utilities Regulatory Policy Act of 1978:
A Perspective from California

Before the Senate Committee on
Energy and Natural Resources

By Duncan Wyse
Director, Policy and
Planning Division

California Public
Utilities Commission

June 5, 1986

Thank you for the opportunity to testify on the implementation of the Public Utilities Regulatory Policy Act of 1978 (PURPA).

It is a pleasure to report that Section 210 of PURPA as implemented by the Federal Energy Regulatory Commission and by State Public Utilities Commissions is successfully achieving the PURPA's mandate "to encourage cogeneration and small power production". Perhaps the Act's success can best be illustrated by the experience in California:

- In 1980, the state's private utilities were contemplating the construction of large and expensive baseload coal plants. Under PURPA, cogeneration and renewable resources have helped to defer construction of such plants, probably into the next century.
- In 1980, California was heavily dependent on oil and natural gas for fuel for its electric utility system. Under PURPA, renewable resources are displacing oil and natural gas use, and natural gas is being burned more efficiently through cogeneration.
- With implementation of PURPA, California's resource mix has become more diverse, reducing the risks of dependency on any particular technology.
- PURPA has created an effective alternative to utility cost-of-service projects. For projects under PURPA, investors - not ratepayers - assume all the risks of cost overruns and poor operating performance. Investors are only paid when they perform.

Figures I through III illustrate the phenomenal growth of the independent electricity industry in California. Today, roughly 6 percent of the electricity supplied in California is provided from independent producers, up from roughly 1 percent in 1980. By the end of the decade, over 10 percent of our state's electricity supply may be provided by independent producers.

Both the PURPA statute and the subsequent implementation rules of the FERC are very sound. By exempting small energy producers and cogeneration from traditional public utilities regulation, Congress created a framework in which independent businesses could profitably provide electricity . FERC's implementing rules provide general pricing guidelines designed to encourage all independent electric production that is competitive with utility production. The FERC rules give states the flexibility to implement PURPA in light of the resource needs of the particular utility and its ratepayers.

While we are proud of our success in the implementation of PURPA, more work remains to be done. At the state level, implementation refinements will be necessary to assure that the ratepayers continue to be well-served by independent producers. We believe that we have the tools we need to accomplish such refinements within the framework of PURPA and the FERC rules.

Background on the PURPA Framework

Section 210 of PURPA is a landmark piece of legislation. PURPA established a category of "Qualifying Facilities" (QFs) that was to be exempt from traditional public utility cost-of-service ratemaking regulation. Those facilities qualifying under PURPA utilized technology that utilities themselves would not necessarily deploy either because of the relatively small size of the facility, or in the case of cogeneration, because the electricity was being provided as part of a larger industrial process. Under PURPA, private business and entrepreneurs were free to develop projects and sell to the utility at prices established by regulatory commissions.

The pricing policy established by the FERC under PURPA was fundamentally different from traditional public utility regulation. Rather than basing the prices paid to these producers on their costs of production, the prices were to be based on the value of the electricity to the utility. This value was to be determined under the principles of "avoided cost pricing."

Under avoided cost principles, prices for the independent producers equal the costs avoided by a utility by taking electricity from the producers. Under this framework, ratepayers are initially indifferent, in terms of the level of rates, between power produced by the utility and the independent producer. However, ratepayers benefit over time as the efficiency of the electric system improves with increased numbers of independent producers. As supply increases, utilities are able to turn off their least efficient plants, and avoid constructing new plants. As a result, the avoided costs fall, resulting in lower rates.

Ratepayers also benefit from the diversification of the resource mix, and from greater reliability created by a large number of relatively small facilities.

The FERC established avoided cost pricing in its implementation rules in early 1980. I would note that the California PUC, after independently studying the issue of pricing policy for independent producers, reached the same conclusion in December 1979. Conceptually, avoided cost pricing has great merit in assuring that all economical alternatives to utility generation are encouraged.

It is very important that FERC gave the state PUCs the flexibility to design regulations to implement PURPA to meet their own specific needs and opportunities. States have very different capacity conditions and resource mixes. Therefore, they have very different needs in developing the independent power industry. For example, a region with over-capacity and baseload electric plants with low operating costs would probably design a very different program under PURPA than a state such as California which has capacity needs, and which relies heavily on expensive oil and natural gas-fired plants. The former would undoubtedly offer much lower prices and different contract terms than the latter. The flexibility the FERC provides recognizes this diversity.

The California Experience

California has aggressively implemented PURPA for several reasons. First, our utilities are heavily dependent on oil and natural gas for fuel for generating electricity. With the OPEC price spikes, and the subsequent rate increases, we have been very anxious to reduce dependency on these fuels. Second, various factors have caused the costs of new coal and nuclear plants to soar, making these technologies less than attractive for meeting future growth or for reducing oil dependency. Finally, California is blessed with the natural resources to make geothermal, biomass, wind, small hydro and solar attractive alternatives as well as a large industrial base capable of deploying cogeneration.

Given the potential for third-party generation, California has proceeded to carefully craft a regulatory program to encourage its development. After extensive comment and deliberations, in January 1982 the Commission issued Decision 82-01-103 which became the framework for pricing for independent production. In that decision the Commission committed itself to establish a set of "standard offers" which would be available to independent producers. These offers were to be complete contracts, somewhat analagous to utility tariffs for electric sales, which would be available upon request by the producer. The purpose of creating these standard offers was to create a symmetrical relationship between utilities (which have a bottleneck on transmission and distribution facilities) and the independent producers. Prior to the creation of standard offers, we were concerned about the pace of utility negotiations with independent producers. The Commission reasoned that utilities, left to their own, do not have strong incentives to negotiate with independent producers.

The standard offers delineated in that decision were designed to meet a variety of needs of independent producers, all consistent with the principles of avoided cost pricing. We recognized that different technologies have needs for different degrees of pricing certainty, and have different performance capabilities. Our offers were designed to meet these different characteristics, and to match payments with performance.

We established four standard offers in D. 82-01-103:

- As-Available Energy and Capacity: In Standard Offer #1, prices vary based on the current marginal cost of the utility. It is somewhat analagous to a spot price in a competitive market. It is particularly well-suited for wind and small hydro facilities with high delivery uncertainties. (See Figure IV)
- As-Available Energy and Firm Capacity: In Standard Offer #2, the energy prices vary as they vary in S.O. #1, but a fixed payment is provided for agreeing to commit to provide reliably electricity during the peak hours of the year.(See Figure V)
- Streamlined Offer For Small Facilities: Standard Offer #3 is like S.O. #1 except that it is simplified for use by very small producers.
- Long-Term Fixed Price Offer: Standard Offer #4 provides prices that are fixed at the outset of the contract for future years, based on the value a facility will have in deferring new utility construction. It is particularly attractive for capital-intensive projects that have difficulty raising capital in the face of uncertain future prices.

The PUC implemented these offers over the course of a two year period subsequent to the issuance of D.82-01-103. The offers were similar to those contemplated in that decision, with the exception that the Long-Term offer emerged with three variations. In the first variation, the prices paid were _fixed_ for 10 years, escalating to reflect anticipated inflation and increases in fuel costs (See Figure VI). In the second variation, the fixed prices were _levelized_ over the ten year period in order to provide earlier cash flow to help in financing (See Figure VII). Strict bond requirements were attached to provide ratepayer protection against overpayments in early years. In the third version, a formula is set rather than specific prices for future years. The formula reflects the utility's _expected_ energy efficiency and the _actual_ fuel cost in future years. Gas-fired cogeneration can effectively use this last option.

In addition to the establishment of the standard offers, the PUC encouraged utilities to negotiate non-standard offers to meet the particular needs of individual facilities. Our standard for reviewing those offers is that the prices be no more than the economic equivalent of a standard offer over the life of the contract. Non-standard contracts have been tailored to meet the variety of needs of independent producers.

The results of these offers have been spectacular.

- o On-line capacity rose from 77 MWs in 1980 to 2781 MWs in 1985. Signed contracts rose from 255 MWs in 1980 to over 15000 MWs in 1985. (See Figure I)

- Independent producer supply as a percentage of all resources has increased and continues to grow. For example, in August 1982, independent producers supplied less than 1 percent of the electricity in the PG&E system. By August 1985, that percentage had grown to over 5 percent. By 1990, the percentage could double. (See Figure II)
- The mix of resources under contract is diverse including cogeneration, wind, biomass, geothermal, hydro, and solar. (See Figure III)

It should be stressed that not all of the signed commitments will actually come to fruition. We expect that a sizable portion of the contracts signed will not come into being for various economic, environmental or other reasons. Nonetheless, it is clear that California is depending on independent producers for much of its future supply.

The standard offers, especially Standard Offer #4, have been so successful that adjustments have become necessary to protect against oversupply. Due to the large number of signed contracts and possible overabundance of supply, the PUC suspended S.O. #4 in April, 1985 for new projects. The suspension was necessary to protect ratepayers from possible overpayments to the independent producers. We are also in the process of adjusting the capacity payments in S.O. #2 downward, again to reflect the fact that capacity needs appear to be met in offers already signed.

This process of adjusting prices to independent producers to reflect current conditions is an integral part of the independent producer program. As conditions change in the utiltity system, prices are reset to reflect the changing need for electricity from the independent producers. In this way, we can draw out resources for the benefit of ratepayers.

Issues for the Future

Implementation of PURPA is fundamentally changing the electric system in California. Rather than relying on integrated utility systems under cost-of-service regulation, under PURPA we are increasingly relying on the price signal to draw out resources from decentralized sources. This has certain advantages, and certain pitfalls as well, each of which are worth examining.

- A major advantage of this pricing system is that independent producers are responsible for all the construction and operating risks, including cost overruns, instead of ratepayers or utilities. Accompanying this risk is the obvious incentive for the producer to keep costs low, and to produce reliably. The painful prudency reviews which we are now undertaking for utility construction projects are not required for facilities under this program.

A second advantage of the program is that decentralization increases the likelihood that small and unusual sources of electricity will be exploited. Hundreds of different projects are under way in California, and entrepreneurs are experimenting with a wide array of technologies. It is highly unlikely that centralized utilities would be able to deploy all these sources.

A central disadvantage of decentralized development of electric generation is the difficulty in system integration. As the amount of independent production grows, concerns have been raised about the ability of independent producers to flexibly provide electricity as needs change over the course of the day or season. Utilities are able to dispatch their own resources to changing conditions. Under current contracts, independent producers are not as flexible. There are also concerns about whether the price signal can assure the kind of reliable performance that a utility expects from its own facilities in meeting future demand.

Much of the current work at the California PUC addresses the concern that independent production be integrated effectively into the utility system. It is not easy, but we are making progress in developing contracts that more precisely meet the needs of utilities as the independent producers grow in importance. While the original version of the Long-Term offer have been suspended, we are now conducting a proceeding to create a new offer to reflect the changing conditions on the utility system.

The Commission is studying three areas in which to refine the independent producer program. For the new offer, we have heard many proposals to limit the availability of the offer to a fixed amount of energy production, and to adjust the price when that particular amount has come under contract. Concerns about contracting for too much capacity could be handled with such a provision.

Another area of promise is the concept of "adders". Under this concept, utilities would make offers for very specific performance characteristics including direct dispatch (i.e., allowing the utility to turn energy sources up and down) for certain periods.

Another interesting concept is bidding. In the event too many independent producers propose to produce, a bidding arrangement could be established to select the producers that most inexpensively offer service to ratepayers.

These and many other difficult issues are before the California Commission as it develops a standard offer for the next generation of independent producers. While I cannot predict the resolution, we are growing more sophisticated as the program grows, and we believe we can continue to develop pricing rules for the benefit of ratepayers.

In closing, I would stress again that PURPA is working, and that the California PUC continues to support it. While much work remains to be completed by the states, the underlying framework of the legislation and the FERC rules gives states the flexibility they need to implement the statute effectively.

Thank you.

FIGURE 1

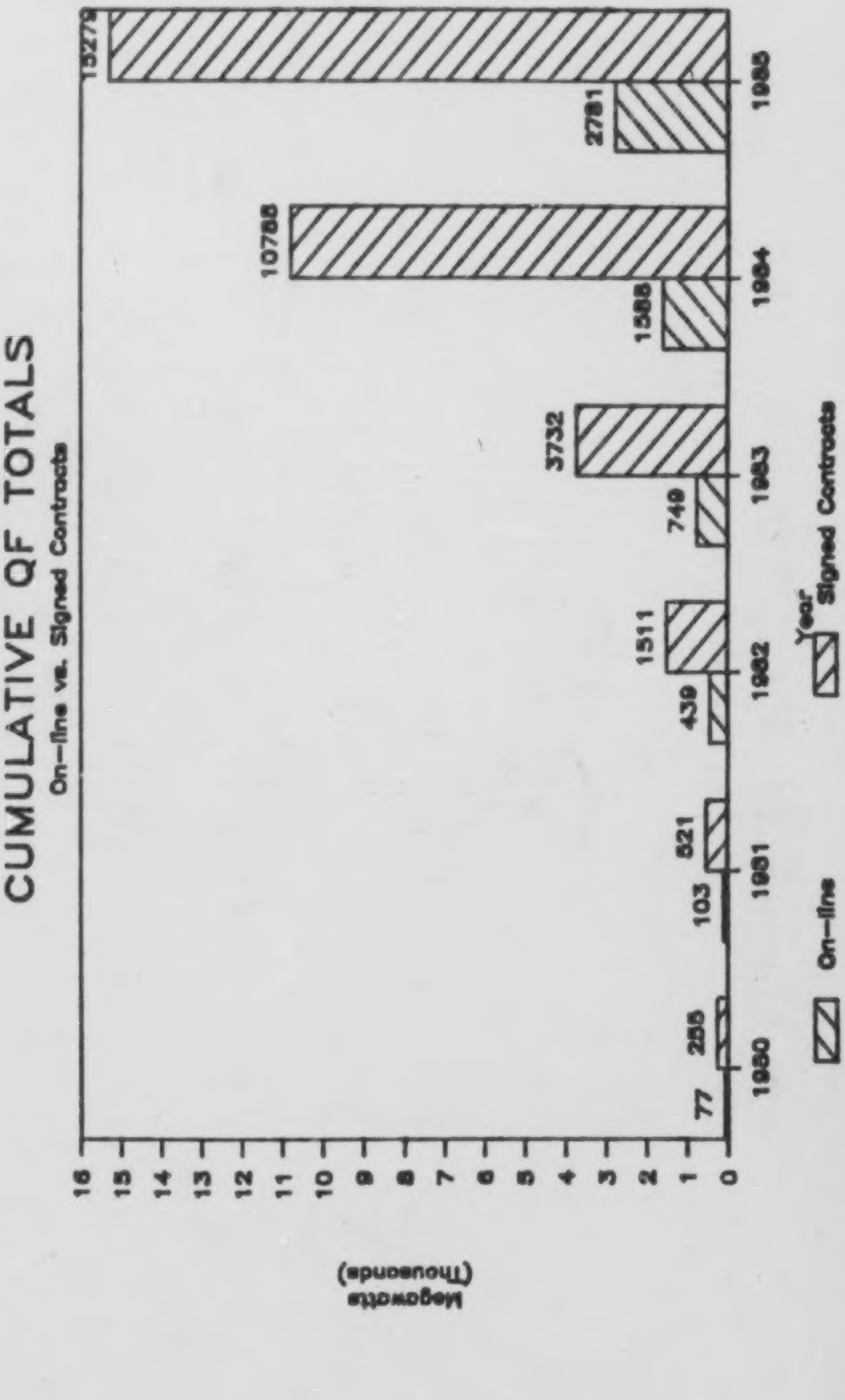

CUMULATIVE QF TOTALS
On-line vs. Signed Contracts
Megawatts (Thousands)
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
Year
1980
1981
1982
1983
1984
1985
77
255
103
521
439
1511
749
3732
1566
10786
2781
15279
On-line
Signed Contracts

FIGURE 2

ELECTRICITY SUPPLY MIX
PG&E – AUGUST 1985 (mwh)

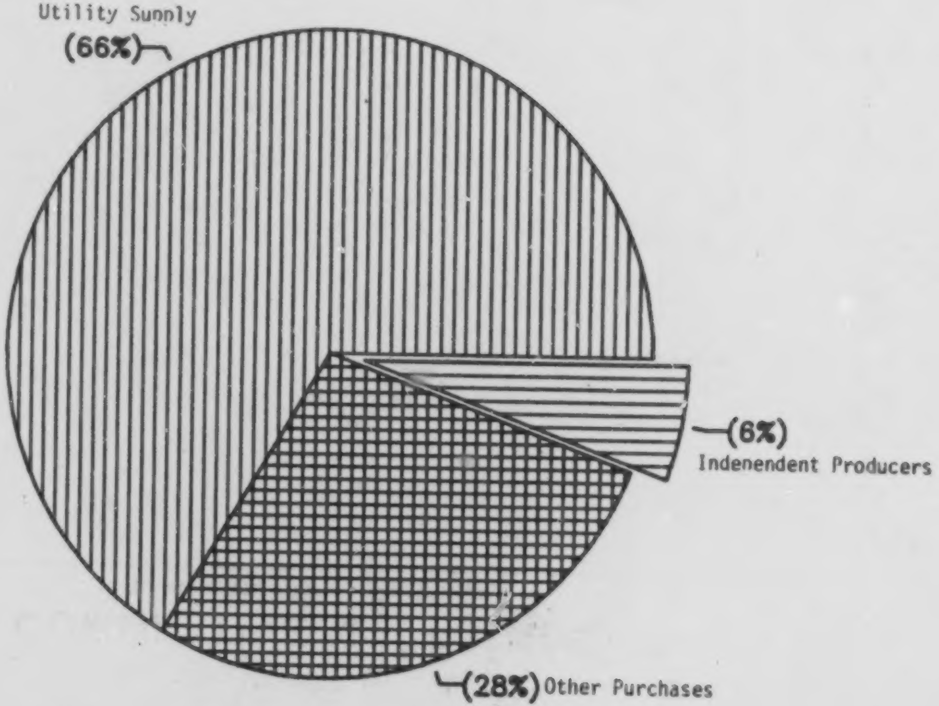


FIGURE 3

SIGNED QF COMMITMENTS – 1985

Megawatts,by technology – SCE & PG&E

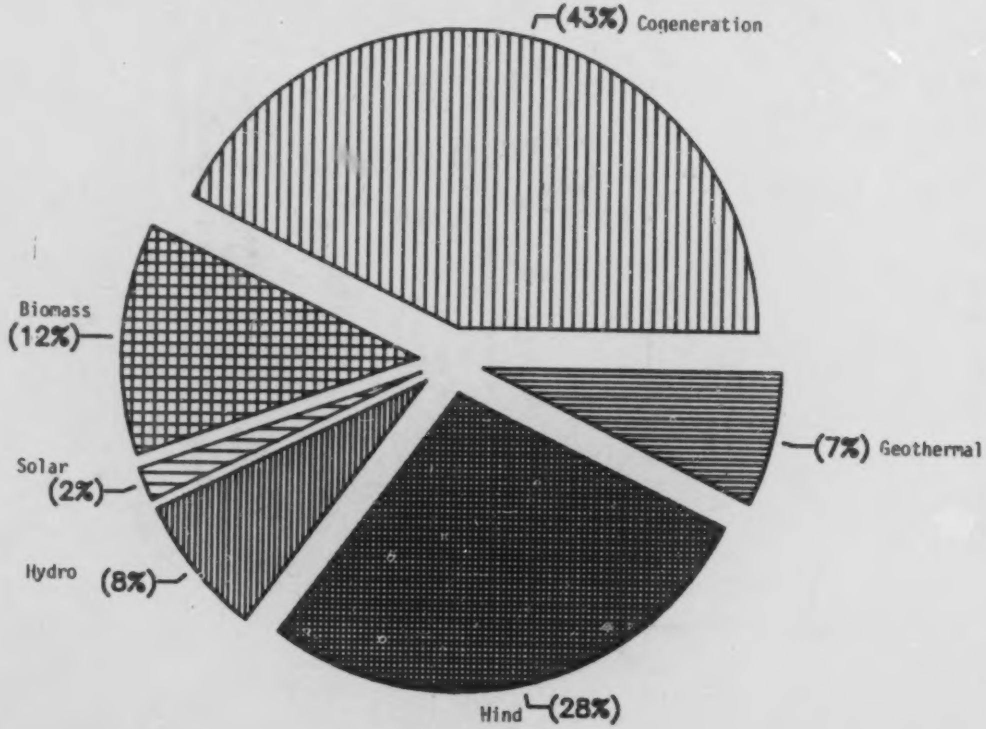
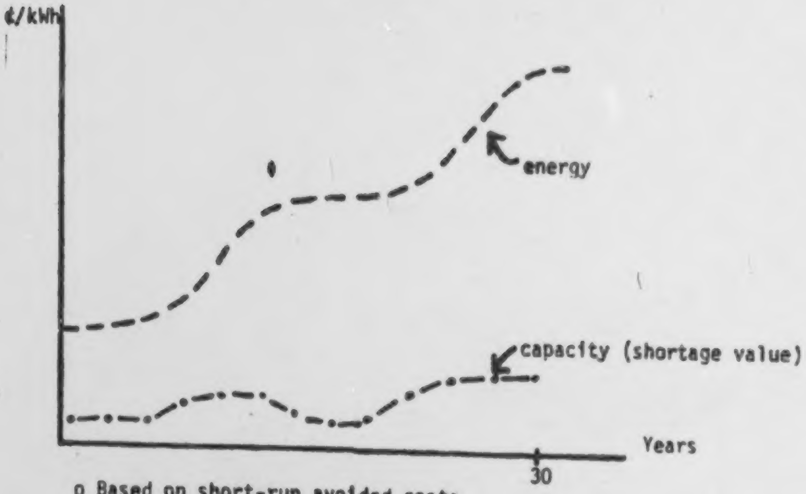


FIGURE 4: STANDARD OFFER #1 (Fully Variable)

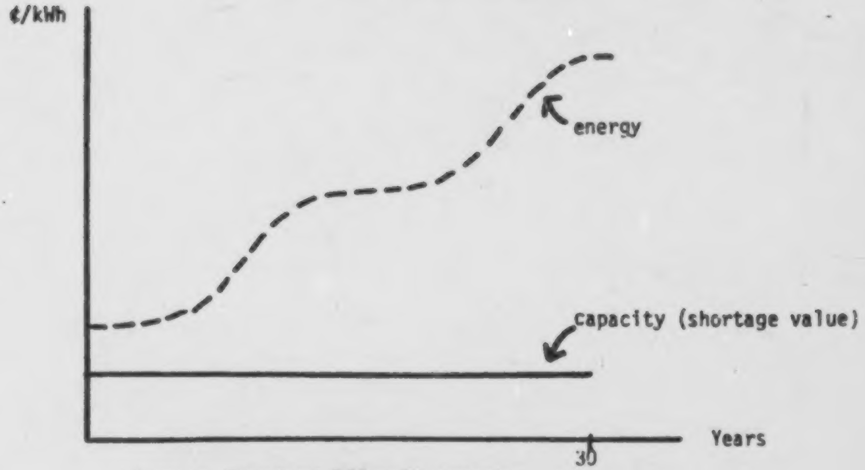


- o Based on short-run avoided costs
- o Variable (actual) energy and capacity payments
- o No performance requirements

Current Status: In place

KEY:		
	– – – –	Variable energy payments based on actual avoided costs.
	–·–·–·	Variable capacity/shortage payments based on actual capacity situation.
	———	Payments based on a fixed forecast.

FIGURE 5: STANDARD OFFER #2 (Fixed, Levelized Capacity)



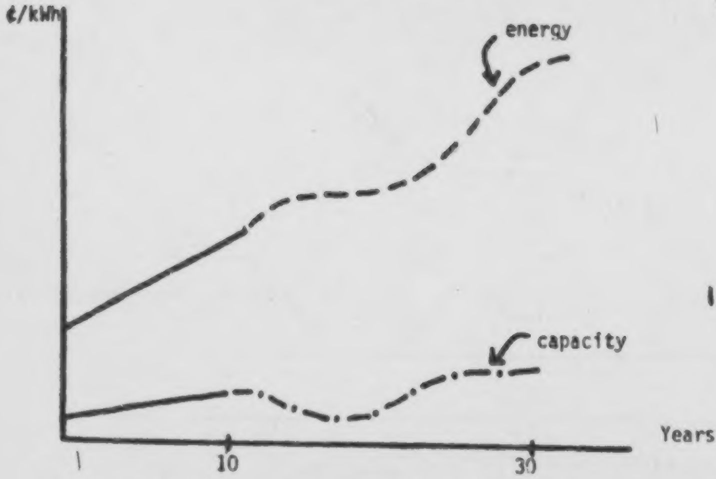
Same as Standard Offer #1 except:

- Capacity payments fixed and levelized up to 30 years
- Performance requirements

Current Status: Temporarily suspended

KEY:		
	– – – –	Variable energy payments based on actual avoided costs.
	–·–·–·–	Variable capacity/shortage payments based on actual capacity situation.
	———	Payments based on a fixed forecast.

FIGURE 6: INTERIM STANDARD OFFER #4 (OPTION 1)
RAMPED UP FIXED FORECAST FOR 10 YEARS



- Based on prices negotiated at Settlement Conference (D.83-09-054)
- 10-yr. fixed forecast for energy and capacity (capacity can be levelized)
- Variable (actual) energy and capacity payments thereafter

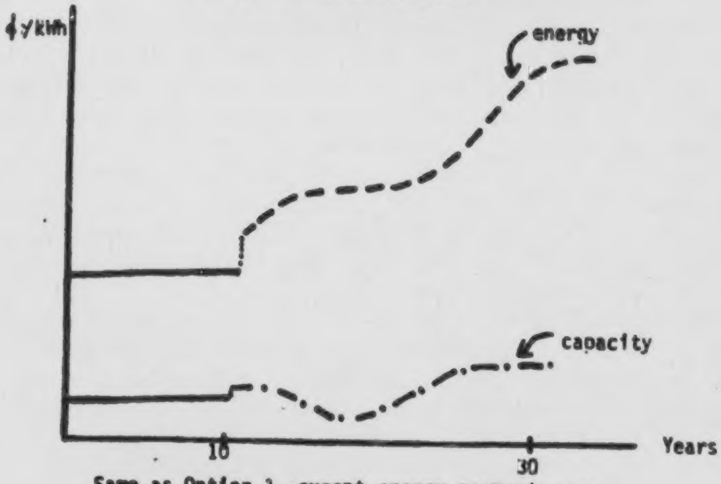
STATUS: Suspended, prices determined by Commission to be outdated and too high for ratepayers, given current energy and capacity situation.

– – – – Variable energy payments based on actual avoided costs

–·–·–· Variable capacity/shortage payments based on actual capacity situation.

——— Payments based on a fixed forecast.

FIGURE 7: INTERIM STANDARD OFFER #4 (OPTION 2) LEVELIZED FIXED FORECAST



Same as Option 1, except energy payments are levelized for 10 years.
STATUS: Suspended

— — —. Variable energy payments based on actual avoided costs.

•—•—•—. Variable capacity/shortage payments based on actual capacity situation.

——— Payments based on a fixed forecast.

The Chairman. Thank you, very much. Mr. Anderson, does the Commission have any plans at the present time for commencing a formal review of its PURPA regulations?

Mr. Anderson. No, sir. I do not believe the Commission has any such plans. Rulemaking could be reopened if petitions were received from industry, or State, or parties. Only one of these has been received in the years; it has been resolved, and I am not aware of any plans at the present time.

The Chairman. It has been suggested that the operating efficiency standards set by FERC for cogenerating facilities are inadequate because they require only minimal amounts of energy savings as a condition for QF status. Do you think the Commission's thermal efficiency standards are adequate?

Mr. Anderson. Yes, sir, I do; I would like to make a comment regarding that. The Commission has several threshold standards that must be passed for oil and gas-fired cogeneration units. The 5-percent operating standard is in combination with an efficiency standard, and the efficiency standard is 42.5 percent, but I believe that threshold may be misintepreted in some quarters.

In actuality, the cogeneration plants we certify have efficiencies that are above that threshold. Considerably above that threshold for oil and gas, especially.

The Chairman. Mr. Swisher, Idaho Power Co. takes the position that because of the excess generating capacity on its system, it has no need for the cogeneration and small power production that it has been compelled to purchase. In their testimony before us, day before yesterday, they used the figure that Idaho ratepayers will pay about $1.2 billion more in rates than they should pay.

Under my questioning, that figure is simply the cost to purchase QF power over the life of the purchase contract. It does not necessarily represent a differential.

What is your response to these points about excess capacity and excessive rates?

Mr. Swisher. Well, in my prepared remarks, Mr. Chairman, I use the analogy that if the Senate diningroom had been the only restaurant in the District of Columbia, and then the Congress had suddenly allowed pizza parlors and Chinese restaurants to come in, you would have got about the reaction from the chefs that we got from the private utilities coming on.

But, once you know that, you also have to know that the new contracts coming on board at the Idaho Power Co., as I said earlier, are in the range of about 45 mils. When we started, in 1981, they were in the 67 mil range. New plants being brought on by the utility itself is not as cheap as the top of either of those ranges. So, I have compassion for their concern, but not a lot of sympathy for them.

It doesn't represent an exposure of the ratepayer any more than baseload central plant of the utility, itself, put in the ratebase, represents exposure. The problem with excess capacity is regionwide. It could almost be said to be nationwide.

Again, I have a hard time feeling bad about that. I mean, if we go back to the time of PURPA and remember the anxiety and the despair almost that went into the National Energy Act, and compare that landscape with today's landscape, what is so bad about all those Pelton Wheels and cogenerating plants? Nothing.

Moreover, the three major industries in the Northwest, excepting the fisheries of Washington, but the three major industries in the Northwest—mining, timber and agriculture—have not come back from the deep recession of the early 1980s. None of them has the vigor today that they had before that recession.

Without the presence of a program for the use of the waste heat and the waste renewables in those industries, we would be in even tougher shape. It has been important in the limited economic comeback that has occurred that a utility's own interest in terms of the rest of its load includes the restoral of those sectors of the economy.

So, I find that the power company still is not able to get past the point when it was the sole provider. It is an ego shot, and it hurts. I feel for them but I can't help them.

The CHAIRMAN. Mr. Gioia, it is evident that New York's method for calculating avoided cost is less generous to the QF's than that of certain other States. Is the primary reason for that the larger amount of excess generating capacity in New York?

Mr. GIOIA. I believe it is; and our conviction that we should not be paying for capacity when we don't need it. We have, in New York, been primarily concerned about getting the alternate energy industry off the ground and we have been dealing mostly with small hydro developers which don't involve the same kind of problems that are posed by other facilities, and it has been relatively modest. We have that advantage.

I think the concern, as we go into the future, is that once these developers get started, they want to continue to develop everything that they have on the drawing board, whether it is economic or not. And as I mention in my testimony, there is a move in the State legislature—there is pressure on the legislature—to continue to increase the subsidy so that they can bring online whatever they want, whether we need it or not.

So we think that the idea behind PURPA and the way we are intending to implement PURPA is that avoided costs should reflect the economics of the situation and, as we move closer to a point where we need the capacity, the price should rise and that should make more facilities more economic and encourage them to come online.

Another important point is that we do not want to focus merely on one option of alternate energy. We are also interested in energy conservation. We have not decided that utility construction is out of the question. We have the option of Canadian imports, and we think it is important that all of those options be considered equally.

The CHAIRMAN. Is it accurate to say that New York has essentially rejected the idea that for large, nonhydro QF projects, the purchase rates must be levelized over the life of the project?

Mr. GIOIA. No; we have not rejected that. We are concerned when making a long-term commitment to avoided costs, and if you have a levelized project, and ratepayers are making advance payments on those estimates. On large projects, those payments go into the hundreds of millions of dollars.

We are concerned, once those advanced payments are made, that those facilities will continue to be economically viable so that the ratepayers have some assurance that they are going to get that money back, and we feel that we have more security with a hydro facility which is not subject to changes in fuel costs, where the facility is basically good for 40 years, the source of water continues, so we are concerned about the security.

In terms of a large project, as long as our avoided costs are right, we are willing to give them long-term contracts on an annual basis where we can make the adjustment annually. If they want a long-term contract based on estimates, then we start to get a little more cautious. We will require adjustment of avoided costs and some security if there are upfront payments.

The **Chairman**. Mr. Swisher, does the Idaho commission take into account the variations in long-term reliability in the determination of levelized rates?

Mr. **Swisher**. Mr. Chairman, not in any formula fashion, but we have done this sort of thing—if an industry brought in a contract that was short term, we simply rejected it because we had no way of protecting the ratepayers from the industry taking the upfront value of levelized payment, and then shutting down in 5 years or 10 years. So we have simply rejected those contracts on an ad hoc basis.

We are concerned, however, and we have requested that the utility with the greatest exposure, the Idaho Power Co., start a system that will work very much like a sinking fund, so that at all times there would be a discount from the rates paid to the QF owner that would serve as a sinking fund against the reliability of the project, itself, and of the seller, himself.

That has been the way we have addressed it.

Mr. Chairman, if I could, I wanted to add one other thing. This may be peculiar to the Northwest, but one reason for the anxiety of Idaho Power is it surrounded with a huge public power service area where very few people live. It is just the character of the country.

Both the water, the runoff, and the forest industry in the public power service area go to the private utilities to sell power. Bonneville Power and FERC and the Department of Industry are so indistinguishable, one from the other when it comes to policy in this category, that we have no way to require a publicly owned utility to honor the act.

Bonneville Power says with a straight face that its avoided cost is the current firm hydro rate. If the private utilities could say that there wouldn't be one Pelton Wheel in the Northwest.

So, to oversimplify its importance, for the committee to understand that the one sector of the utility industry that does not obey the Federal law is the Federal sector.

The **Chairman**. Mr. Wyse, in light of the recent suspension of Standard Offers No. 2 and 4, what does the California commission envision will occur in the next few years regarding alternative energy sources?

Mr. **Wyse**. Well, we have, of course, a lot of contracts already signed and we are going to be managing those contracts and we hope those will come online to provide energy for the ratepayers.

We are in the process right now of revising Standard Offers No. 2 and 4, and I suspect, given the changed conditions, that they won't be as high as they were. But we will put into place modified offers to replace them.

The CHAIRMAN. Dr. Thomas, do you have any evidence that there is any backdooring of the Fuel Use Act through the guise of cogeneration?

Dr. THOMAS. Backdooring, meaning burning gas when they shouldn't be burning gas?

The CHAIRMAN. Yes.

Dr. THOMAS. I think that we are burning more gas, or receiving more electricity generated from gas because of cogeneration than we would ordinarily, if only the Fuel Use Act existed and PURPA did not exist.

The CHAIRMAN. And the avoided cost rule that you have is based upon natural gas-fired plants, is that correct?

Dr. THOMAS. Well, we set a cap and generally the cap is lignite energy and lignite capacity, because that is the next plant most of the utilities plan to build.

The CHAIRMAN. If that is the case, and if you get natural gas burned through cogeneration, then the consumers are paying a much higher cost, are they not, for that gas-fired capacity than they would have if it were just generated by the utility in the first place?

Dr. THOMAS. That depends on a day-to-day basis on the cost of gas. When our rules were set——

The CHAIRMAN. Well, gas is less expensive than lignite, isn't it?

Mr. THOMAS. Right now.

The CHAIRMAN. Right now.

Dr. THOMAS. It was essentially a tradeoff in 1984 when our rules were set, and I wouldn't be in public service if I was able to predict 2 years in advance. So, right now, it looks like they are paying more, but they are still paying considerably less than they would have, had the utilities gone ahead and built the lignite plants.

The CHAIRMAN. If they built the lignite plants, but what would have happened if they had built gas-fired plants?

Dr. THOMAS. Well, if the gas-fired plants had been built and they had lock in long-term contracts, which they were prone to do in 1984 on gas, then it would have been essentially in the same area. Today, it would be cheaper for gas.

The CHAIRMAN. Senator Evans.

Senator EVANS. Thank you, Mr. Chairman. I have been struck by the three panels we have had so far, Mr. Chairman, at the unanimity expressed. You have joined with the previous two panels in that unanimity. The cogenerators or those who are working under PURPA regulations, all think that it is just swell. The regulators all think they are doing a superb job, and the utilities are uniformly unhappy, which causes me to think that something is wrong somewhere.

There ought to be a little bit of unhappiness or division among each of the groups, but there does not appear to be so far.

Let me start with Mr. Anderson. You mentioned on page 7 of your testimony that the nonregulated utilities, or State commissions, could apply for waiver of the avoided cost rule which may be granted if the applicant demonstrates that full avoided cost is not necessary to encourage cogeneration and small power production.

Has anyone ever requested that waiver? Or, have waivers ever been granted?

Mr. ANDERSON. No, sir. None have been requested.

Senator EVANS. What does that indicate to you?

Mr. ANDERSON. Hopefully, it indicates that the flexibility of the rules are working well and are well received.

Senator EVANS. How does that jibe with the repeated testimony we had from the utilities that are chaffing under these rules and concerned about the levels of avoided costs as they have been set? They do not have a chance to appeal to the commissions. They have to appeal through the regulatory commissions, and apparently the regulatory commissions are not making any requests for waiver or for change.

Mr. ANDERSON. They could petition to reopen the rulemaking and change the regulations and implementation.

Senator EVANS. Would this hearing and the series of hearings be another way to approach that same——

Mr. ANDERSON. Certainly.

Senator EVANS. Perry.

Mr. SWISHER. Senator, the FERC, oversimplified, doesn't really do the pricing, and of course, the avoided cost action is different in each case. Most States have used the FERC rule to say any plant coming on that is over 10 megawatts must be individually negotiated with the utility. I think that is especially true in the two States sitting just to the left of me.

Senator EVANS. When you say individually negotiated with the utilities, does the commission then sit by as a noninterested observer, and the utility has the right to say we don't want it, and we can reject at whatever level the negotiation is conducted?

Mr. SWISHER. Yes.

Senator EVANS. Is that really true? How about other commissions? I do not detect that that is accurate.

Mr. SWISHER. For example, in your neighborhood, the Potlatch Corp., it has a contract with Washington Water Power and has not been consummated and been under negotiation for 4 years. It has not been mandated by the commission.

Senator EVANS. How about in New York?

Mr. GIOIA. Well, we have required utilities to enter into contracts for avoided costs, and as I said before——

Senator EVANS. Into negotiations as to what avoided costs ought to be?

Mr. GIOIA. No. We decide what the avoided cost should be.

Senator EVANS. And then they are required to enter into negotiations?

Mr. GIOIA. Yes. The difficulty comes——

Senator Evans. What is there to negotiate at that point?

Mr. GIOIA. Well, the difficulty comes when the developers generally want long-term numbers, where we have different rules and they are not as binding, or they want up-front payment. For example, a hydrodeveloper will come in and say we can't finance with annual avoided costs. We want up-front payment, and then we will make the reconciliation after year 10 or year 15. That is a different story.

Once they start asking more than the Commission has required, then negotiations result. But even in respect to contracts like that, the Commission has gotten involved and set ground rules.

Our feeling is that if we left it to the utilities to negotiate these, we wouldn't have contracts negotiated. Utilities do not want to develop this alternate source of generation. We feel we have to mandate the terms of these contracts.

Senator EVANS. I am not sure what term I would apply to that. It doesn't sound much like negotiation; it sounds like careful guidance along a certain path.

Mr. GIOIA. That is exactly right. They have full input in terms of how we determine avoided costs. We have hearings and they have every right to argue what they should be. But once they are established, that is it.

But, as I say, the developers frequently come in and want additional benefits, and then there is some negotiation.

Senator EVANS. Dr. Thomas, what about you?

Dr. THOMAS. In Texas, the avoided cost is a maximum and then the negotiations start below that. Since we have regular cogeneration that already exists, the competition is quite fierce. They negotiate on price and they negotiate on dispatchability of the power, the duration of the contract, and then we have encourage the utility companies to differentiate based upon how good their natural gas contract is, how subject is it to being curtailed?

Senator EVANS. Well, the utility under your system gets to the point where they say, "Look, we are just swamped in extra power, both of our own generation and cogenerators, and you still have a long line up outside the window, you require them to negotiate."

Dr. THOMAS. Only the ones who need capacity are required to buy capacity, otherwise they just buy avoided energy.

Senator EVANS. If they buy capacity, how much is enough before there is excess that causes them to say no more?

Dr. THOMAS. They generally run in reserve margins of about 20 percent.

Senator EVANS. When they get to 20 percent, do you then say to the utility, "OK, you can negotiate all you want but you do not have to consummate negotiations?"

Dr. THOMAS. They don't even have to negotiate at that point for capacity.

The CHAIRMAN. Could I ask a question? When you are talking about excess capacity, over what period of time?

Dr. THOMAS. You mean for the utility or the cogenerators?

The CHAIRMAN. Yes. There is a match up between the capacity of the generator to provide electricity. There is a period of time in which the utility may have adequate reserves or excess capacity. Do you look at that period of time and match those up in making that determination?

Dr. THOMAS. Yes. If we are running a 20-year forecast, and we can see over the next 20 years that these are the reserve margins we want, we are a little unusual in that we are still building plants in Texas, and so we have plants which are on the drawing boards and are scheduled and ready to go. So at that point, it becomes a tradeoff whether the utility starts their own plant, or you bring on a cogeneration plant.

Senator EVANS. In fact, Mr. Anderson, I do not know how familiar you are with the Senate bill which has passed and is now in conference on hydro relicensing. A certain portion of that—and let me just read the particular sections that talk about no hydroelectric project shall be considered a small power production facility, other than by means of an existing dam or diversion unless—and then there are several proviso, a government dam or such project that meets the terms and conditions set by fish and wildlife agencies, et cetera. Then it goes to the next section; the amendments made by section 10 of this Act shall not apply to any hydroelectric project for which an application for license or preliminary permit was filed with FERC on or before April 11, 1986.

I guess, first, what is your general view of that proviso in this new Act?

Mr. ANDERSON. Senator, I have not reviewed that. It might be better if I could respond for the record.

Senator EVANS. Good. It would be helpful because it ties into your statements on page 13 which talks about the consideration and denial of a request by certain environmental groups that you amend your regulations. I understand that that is now being litigated.

With litigation now underway, can you tell me, however, what the rationale of the commission was in denying the petitioner's application?

Mr. ANDERSON. I can provide a copy of the commission's denial, of January 1986, in that case. In general, I believe that it indicated that there were no new proposals, no substantive things or tools that the commission could use that appear to be better than what the commission was presently doing.

Senator EVANS. Is not the commission, itself, beginning to look in some different ways at not only individual projects, but clusters of projects, river basin planning and development?

Mr. ANDERSON. Yes, sir. They do have a procedure that has been implemented in the last 24 months.

Senator EVANS. Is it the intent of the commission to extend that concept, which I understand now has been applied to three river basins?

Mr. ANDERSON. Three; yes, sir.

Senator EVANS. Is that going to become essentially a standard in the future, where you have the potential, at least, of multiple projects in river basins?

Mr. ANDERSON. Well, it certainly, once the commission goes down a path, it is hard to change that or reverse it. I think there have been 40 river-basins that have a potential, or request, or a suggestion that they receive the cumulative cluster impact analysis. Largely, it is a policy question that the commission has to address in a case-by-case, river basin-by-river-basin basis. As those come up, the commission, under the guidance of the Chairman, would look at those.

I really could not predict whether there will be another one or dozen, or when.

Senator **Evans**. Mr. Swisher, you had an interesting comment on page 5 of your testimony, where you said,

> If you find significant instances of industry designing wasteful energy consumption into their plans to retrofit because cogeneration is the artificial stimulate for their strategems, set thermally based criteria as the disincentives.

We had testimony when the utilities were here that in some instances, industries were designing cogeneration plants that would produce six to seven times as much electric energy and waste heat as the industry itself needed for its own purposes; sell it into the power grid at a pretty high price, and then buy the electric power back at about half that price.

Is that in your view appropriate? How big should you get? How far beyond your own needs should you go under those circumstances before something of this sort——

Mr. **Swisher**. Well, Senator, I assume the Congress is taking a hard look at the 1970's prohibition against natural gas under the utility boiler.

Senator **Evans**. It seems to me that that is—at least, it has been brought up a number of times during these hearings. I suspect that that is, certainly at least, a potential outgrowth of the hearings we are having right now.

Mr. **Swisher**. Part of the cure would be to address that question, because we get into what is called combined cycle, use of natural gas, that is the biggest problem the utility has in my judgment.

In our region, as you know, that is not a consideration at the present time. It is a way of life in Texas.

So, it would seem to me that the real cure comes in your treatment of the constraints against the utility use of natural gas; that at that time you can set the thermal standard in terms of efficiency without having to get into the rules and regs. It would take the pressure off the utility and take the pressure off of FERC.

You simply shouldn't be able to burn one fuel and turn what is supposed to be an industry into a powerplant, and that is where the paranoia exists at the utility; because of that threat. The Texans are pretty sophisticated in the way they play that game, but almost nobody else is.

It needs to be addressed. If there is any area that the Congress needs to look at, it needs to look at that one.

One certainty is that the assumption that natural gas supply is limited by the same geology that limits oil resources, that assumption from the 1970's is archaic. Supply of natural gas is going to be considerable. This planet is flatulent and it is the one area in which——

Senator **Evans**. The trouble is the flatulence is intermittent; not constant.

Mr. **Swisher**. Yes, well it usually is.

But, even so, what has been learned since the 1970's, really should be addressed in allowing the gas back onto the utility boiler, and in preventing QF's from becoming simply disguised electric plants.

Senator **Evans**. Even leaving that aside, the particular problems of the Fuel Use Act, and taking some other kind of fuel or some other generating capacity, are we at a point where we have perhaps inadvertently, in our enthusiasm for PURPA, allowed a situation where there isn't the proverbial, level playing field. In other words, where someone may decide that they are getting into a whale of a nice business by creating a very big powerplant and have the advantage of investment tax credits and certain other kinds of benefits which are available to the developer but not available to the utility.

The question of ownership, of course, is another one. Are we creating a situation where, in order to gain the power production from these individual cogenerations or power producers, created a possibility of competition that isn't even competition?

Mr. SWISHER. Senator, in a word, "No." We are not getting that much. What we are getting is a coincidence.

Senator EVANS. I am not talking about what we are getting now, but what we might potentially get.

Mr. SWISHER. I think where the fear comes from, cogeneration has matured at the same moment, almost, that the plants that were planned baseload by the utilities in the 1970's are being completed. So all of this surplus capacity is arising at the same time. That is a moment in time.

It will change. It is not going to be like that. The movement downward of avoided costs as the surplus is extended into the future is the remedy. That part of the PURPA Act seems to work best of all and, I think, it was given the least attention when it was written. It is working, in my judgment.

Senator EVANS. In your view, is there any danger that in our enthusiasm for PURPA and continued generation, at whatever levels we set avoided costs, we overemphasize the generation side and underemphasize the potential for new energy, I would say from better efficiencies or from conservation?

Mr. SWISHER. Well, no. I don't think the conservation ethic, once adopted, is reversible. Your own experience as chairman of the Northwest Power Council was that once you started, even the utilities get hooked on it in the sense that conservation will buy them a resource cheaper than the construction of new plants.

Senator EVANS. That was not universally held, however. We had great difficulty in convincing the homebuilders that it was a good investment, and a good many others, that it was a good investment.

Mr. SWISHER. That is still a difficulty, but part of that is because, if you will pardon me, the people in the temperate climates of Seattle and Portland are prescribing triple glazing for the residents of Northern Montana. It is just a regional version of what Washington, DC, did to us.

Senator EVANS. I think the whole idea was to establish, and I think that they were talking about the fact that triple glazing was even cost-effective in the temperate climate, as well as the others.

Mr. GIOIA. Senator, if I could briefly comment. I don't see the problem as PURPA. I see the problem as the fact that we have had such a disastrous experience recently in building and paying for major central generating stations, that the States, on their own, with respect to how they interpret and implement PURPA, and also with specific legislation, will be running for specific options, whether it is energy conservation or alternate generation, irrespective of the cost and reliability considerations.

I think that the problem is developing at different paces in different States. In New York, we have the luxury right now where we are dealing with completing three major plants, but we don't need the capacity now.

What I am urging is that we take the time on the State level to look at these options, to make sure there is a level playing field. Some other States have to deal with the issue a little more quickly, and so that creates their own problem.

But I don't think the problem is fundamentally in PURPA, or that fundamental changes in PURPA are necessary. I think it is a matter of the States not panicking as a result of a bad experience, and looking at all the options.

Senator EVANS. In your view, is the biggest difficulty or complexity, in your responsibility in a regulatory commission, under PURPA, trying to establish what is a fair and responsible rate for avoided cost?

Mr. GIOIA. I don't think that is any bigger of a problem than many other problems we have. As I perceive it, the problem is that politically, as far as the public is concerned, they are very, very concerned about the next, major central plant. And developers who want special treatment, and politicians who are concerned about that are pressing us to go beyond perhaps where we should be going.

I think without that political pressure, our ability to work with PURPA is adequate and I don't think that is a major problem.

Senator EVANS. Mr. Swisher, you mention on page 6 of your testimony that BPA, on behalf of its preference customers, says with a straight face that its avoided cost is the current price of surplus firm hydro. What should their avoided costs be?

Mr. SWISHER. They should not be surrogate, Senators, for the public utilities. They are a marketing agency, and because those utilities buy from BPA and are BPA's preference customers, BPA's avoided costs, just by waving that wand is their magic avoided cost.

So the effect is that in the marketing region of the Bonneville Power Administration, all preference customers ignore PURPA. That was not the act of Congress; that was the act of BPA.

Senator EVANS. That doesn't get to my question, however. You say it shouldn't be the cost of surplus firm hydro; what, in your view, ought it be? How should they calculate their avoided costs?

Mr. SWISHER. Under the Northwest Power Act, they have what is called a Seven-F category of new resources, and they haven't been acquiring any. I think a couple of bulb turbines at Idaho Falls—but, whatever the cost of their new resources are, how about the cost of Whoops No. 3 as avoided plant?

Senator EVANS. They have avoided that one. Not as well as they avoided 4 and 5. But it still gets to the fundamental question, which sort of troubles me.

I think in the Northwest, maybe beyond Bonneville, maybe taking the entire needs of the region, each successive year, even since the passage of the Pacific Northwest Power Act, we have had what we now lovingly call the jaws—the high and low estimates of the future—and the jaws each successive year have continued to come down until now the most likely future of power production does not call for any central plants in the Northwest beyond the turn of the century.

Under circumstances like that, what ought the avoided costs—what should the avoided costs be? When an applicant under PURPA comes to sell to a utility, what should that utility tell them? Or, what should the regulators say?

Mr. SWISHER. Well, this is what the regulator is saying in Idaho, and now in Washington, as of this spring. Washington State.

We are saying on a utility-specific basis, for instance, that Washington Water Power will require no additional resources of its own before 1993. I believe that is the year. And so we calculate avoided costs as being the life of a plant, 35 years. We include that period of surplus in the calculation of the costs of running that avoided plant, and the effect is to bring down the rates for PURPA power, and they have moved down by at least 20 mils, at least in our jurisdiction, because we do include the projection of the surplus.

Senator EVANS. But would that be extended, in your view, if you took another utility whose surplus was 20 or 25 years? At what point do you let them off the hook and say, look, you do not have to negotiate any more PURPA power?

Mr. SWISHER. We don't ever do that because if we did that, there is not a utility extant in the United States that would need 1 kilowatt. That utility would always say, we don't need it.

Senator EVANS. Well, what if there is a utility that honestly does not need any more, and is not like to need any more for an extended period of time in the future? Are you going to force them to buy PURPA power?

Mr. SWISHER. It is not a question of force.

Senator EVANS. Sounds like it.

Mr. SWISHER. Well, yes, it is force.

[General laughter.]

Mr. SWISHER. It is the same relationship with the utility that the utility has with its customer, Senator.

Now what happens is that no utility is freestanding anymore. There is no longer any utility that is required to match its capacity with its demand, and so what will happen over time is that electricity, which is a highly portable form of energy can go where the need is, and as I discussed in the prepared remarks, we have had that wonderful California situation going on for so long that none of the State jurisdictions has appropriately addressed moving PURPA power beyond the jurisdiction of a specific utility.

Only California has done that in the West; no other State. We are going to have to address it, but I don't think Congress can.

Mr. WYSE. Could I try answering that question?

Senator EVANS. Surely.

Mr. WYSE. If you are in a condition where there is really no capacity needs for a very extended period of time, you would pay a very low capacity price on the avoided cost calculation, approaching zero. You would still want to have an avoided cost contract that reflected the energy cost of the utility. If an independent producer could beat the utility's operation cost, then it would be economical for them to come on line.

So you would still have an avoided cost contract, but it would be a much lower price.

Senator EVANS. We always have to readjust our thinking in the Northwest compared to other parts of the country because we are simply not capacity constrained, or energy constrained, and so that becomes a guiding point.

Do you suggest across the board that in terms of cost of energy, the avoided cost is the cost of energy generated by a new plant, or, again, getting back to Mr. Swisher's idea that it ought not to be the firm power, but the firm hydro surplus, but that is essentially where the power comes from, will come from, is coming from. That is where the energy is coming from.

Why should any avoided cost calculation be associated with a new nuclear plant or new coal plant if it looks as though for the rest of the century and beyond we are going to get power cheaper?

Mr. WYSE. The way we would calculate it, and I am not that familiar with the Northwest condition, but it would be on the incremental operating costs at existing plants, not new plants.

Senator EVANS. How about New York?

Mr. GIOIA. That is how we stand.

Dr. THOMAS. Ours is still a negotiated price. So if one cogenerator is not willing to sell, then there would be another cogenerator immediately there who is willing to cut the price.

Senator EVANS. But if the utility does not need anything, are they able to say we do not need anything; we do not care what the price is. None of our prices are as low as we can get it for?

Dr. THOMAS. If they don't need any capacity, then they only have to buy that energy which is cheaper than theirs.

Senator EVANS. Perry.

Mr. SWISHER. Senator, could I add? We have a brand new kind of witch doctor in the regulatory hearing room, and that is the person who runs the power supply model. The economist who is trained as what is called a forecaster.

You had the experience as Governor of seeing the forecasts from the utilities who have said that we would increase our electric consumption by 7 percent per year, incrementally, exponentially, for the balance of this century.

Now, because that forecast turned out to be so wrong because of elasticity, economists have now come in and taken whole pieces of turf away from the attorneys, the accountants and the utility executives. They come in and they read their magic power supply theories, and they tell us now. They are a new group, the new forecasters, and I suspect they are going to be as wrong as the last batch.

They are the ones who say we are not going to need any new plants until the 21st century.

Senator EVANS. I would hope they would be a little more accurate because I think what we found when we got into it was that there was not any effective forecasting being done.

In the Northwest, at least, it was some of the utilities forecast, where 130 utilities each added up what they optimistically thought would be their needs, added in all of their optimistic reserve requirements and sent them into a central place, and they added them all up.

I cannot prove it, but I will bet I am right, that they tripled, quadrupled, quintupled counted some of the expected new industrial plants, with about half a dozen utilities all thinking that some plant was going to settle in their territory, when it was obvious that there was not going to be six plants settled. So, it was not so much that the forecasters, it seems to me, were wrong in that area; there just were not any sophisticated or, really, well done forecasts.

I hope we are better off than that right now. You are right; they may be just as wrong, but they will be as wrong having done at least some better try at being right.

Mr. SWISHER. They will be better paid.

Senator EVANS. Well, that is probably right, too.

Thank you, very much, Mr. Chairman.

The CHAIRMAN. Gentlemen, thank you, very much. There may be some questions for response in writing. We will submit those to you and would appreciate your prompt response for the record. Thank you, very much, for your testimony this morning.

Next, we will hear from a panel that will discuss small hydro development, and environmental costs and benefits.

Our first witness is Mr. Botkin.

Gentlemen, your entire written statements will be placed in the record in full. You are invited to summarize, hit the high points, and deliver the statement in whatever manner you desire.

STATEMENT OF JAY M. BOTKIN, ON BEHALF OF THE NORTHWEST SMALL HYDROELECTRIC ASSOCIATION

Mr. BOTKIN. Thank you, Mr. Chairman. My name is Jerry Botkin. I am a native Washingtonian and I am president of South Fork Resources, a small hydroelectric company.

I am before you today as a representative of the Northwest Small Hydroelectric Association, known as NSHA.

NSHA is an association of all parties involved in small hydro issues of the Northwest: utilities, municipal developers, private developers, consultants, equipment suppliers, agencies, and tribes.

Before addressing the present role of PURPA in the Northwest small hydro market, I will briefly review some history behind small hydro development.

In the period of 1978 through 1981, Congress and the Federal Government selected small hydro as a preferred new energy technology. Congress passed several acts which encouraged small hydro development; PURPA, the Energy Security Act of 1980, the Crude Oil Windfall Profit Tax Act of 1980, and others.

The Department of Energy offered low-interest loans for feasibility studies, and licensing of small hydro sites. The Corps of Engineers and the Bureau of Reclamation developed and promulgated manuals for the assessment of small hydro sites.

All of these encouraged a fledging, small hydro community in the Pacific Northwest, an encouragement that the Federal Government felt was appropriate as small hydro was a desirable alternative to foreign oil and central station thermal generation.

My only involvement in small hydro began in 1980, in large part due to these incentives. Even with the background as an ardent, outdoor recreationalist and environmentalist, I was convinced that small hydro presented a better option than central station thermal generation.

I therefore initiated the planning of two small hydro projects. These projects were the Twin Falls project and the Weeks Falls project, which in aggregate are 24.5 megawatts in power. These projects were licensed last year in May. They have received national recognition as projects that were developed as responsively and sensibly as the fish and wildlife agencies could hope for.

The current status of small hydro though is an anomaly. Despite the huge numbers of permits which have been issued over the past 5 years, and which are often noted by the opponents of small hydro, few projects are on line or under construction.

Within the 4 States of the Northwest, only 61 small hydro projects with installed capacity of 127 megawatts have been completed. These projects, which are dominated by five large projects as existing facilities and numerous projects of less than one megawatt represent less than 60 average megawatts, and therefore, less than one-half percent of the total regional load.

For States in which data are available on new dam sites versus existing sites, less than 25 percent of the on-line projects are new dam projects, and less than 8 percent of the installed capacity comes from projects at new dams. Most significantly, actual PURPA or QF type projects, in the State of Washington, there are only four to date, and this is for a total installed capacity of 7.3 megawatts.

I was asked today to address specifically the role that PURPA has played in Northwest Small Hydro Development. PURPA was a reasonable attempt to recreate a free market situation in energy generation. As such, it has succeeded moderately well. Few projects have actually been built in the Northwest, though, due to low avoided costs, which indicates that a free market is in fact at work.

Furthermore, as PURPA does not in any way limit the environmental regulatory process, it has not resulted in any environmental degradation. Although flaws have been noted in the PURPA process, specifically that discrepancies in avoided costs between publicly owned and private utilities have caused some desirable projects to be foregone, on the whole, PURPA has been beneficial to the region.

The regulatory system in place for small hydro is rigorous, to say the least. In the State of Washington, a developer may well work with some 47 Federal, State, and local agencies, to arrive at a series of enabling permits, licensing and hydraulic permits and water rights capabilities. This does not include public involvement, which through media notice can effectively bring into the consultation process additional public parties and Federal, State and local entities which may have an interest in the development of a given project. On top of these is consultation with the various Indian tribes that may be involved.

The total cost of successfully permitting a typical small hydro project may be up to $500,000. It must be recognized that opposition to small hydro development in the Northwest is not a choice which can be made in a vacuum. It represents a clear choice to pursue other energy options.

Most of those options have negative environmental and economic aspects which rival or exceed those of small hydro. If the private developer component of the small hydro industry in the Northwest were to end, due to the withdrawal of PURPA, strengthened regulatory constraints, or other factors, the established small hydro community would likely disband forever.

Already the existing community has had defections due to disillusionment with the process. Any further pressures will likely remove the remaining vestiges of private enterprise in the industry.

Thank you.

[The prepared statement of Mr. Botkin follows:]

THE NORTHWEST SMALL HYDROELECTRIC ASSOCIATION

PRESENTATION TO THE

PURPA OVERSIGHT HEARINGS

JUNE 3 AND 5, 1986

SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

Northwest Small Hydroelectric Association

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BEFORE THE UNITED STATES SENATE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
PURPA OVERSIGHT HEARINGS
WASHINGTON, D. C.
THURSDAY, JUNE 5, 1986

INTRODUCTION

My name is Jay M. (Jerry) Botkin. I am a native Washingtonian, and I am President of South Fork Resources, a small hydroelectric development company. I am before you today to represent the Northwest Small Hydroelectric Association's (NSHA) position with respect to PURPA and this oversight hearing.

NSHA is incorporated in Oregon, headquartered at P. O. Box 7528, Bend, Oregon 97708. Its membership includes companies in the four Northwest states of Idaho, Montana, Oregon and Washington. Membership includes private and municipal developers; investor owned utilities; public utilities; Indian tribes; irrigation and other water districts; cities, counties and other municipal governments; engineering firms; consultants, including environmental scientists, financiers, attorneys and economists; contractors; manufacturers; timber companies; state agencies and others. Membership also includes companies located outside the Northwest region.

NSHA has supplied services to its trade association members since its incorporation in 1981. I have been a member since 1982.

I am and have been directly involved in all aspects of the development of two small hydroelectric projects in the State of

Washington. One of these has just recently entered construction; the other, unfortunately, is held up in a shorelines dispute. As a result of my experience and active participation in the industry since 1980, I have personal knowledge of the events surrounding the Federal Energy Regulatory Commission procedures as they affect small hydroelectric project development in the Northwest region (Idaho, Montana, Oregon and Washington States), and most specifically in Washington.

HISTORY OF SMALL HYDROELECTRIC DEVELOPMENT AND CURRENT DEVELOPMENT INCENTIVES

HISTORY

Much of the earlier development of an electrical grid in the Pacific Northwest and in the nation was based on small hydroelectric development. In the Northwest, projects such as Snoqualmie Falls and Willamette Falls were crucial to early economic development.

By 1920, hydroelectric generation had become an established industry and, in response, Congress passed the Federal Power Act establishing federal interest in hydroelectric power generation. Along with this new interest in energy production, the Federal Power Commission (now called the Federal Energy Regulatory Commission, or FERC) was directed to regulate all nonfederal development of hydroelectricity and natural gas. Subsequent court cases, including the U.S. Supreme Court in the 1946 First Iowa decision, found that the FERC role was to be preeminent in the regulatory process.

Despite the passage of the Federal Power Act, small-scale hydro saw relatively little growth from 1920 until the mid-1970's for several reasons. First, the cost of producing power at smaller or "marginal" hydro sites was relatively high in times of cheap oil. Second, the utilities preferred the profit potential of large central station thermal projects. Third, these utilities, which owned the transmission grid, had no incentives or regulatory requirements to purchase power from others that might develop sites. Simply, the utilities preferred not to build small hydro and there were no incentives for others to fill the void.

NEW DEVELOPMENT INCENTIVES

Beginning in 1978, a national concern with the over-reliance on large thermal resources manifested itself through various federal, regional and state incentives. The most visible of these was the PURPA power marketing provisions, but others were also effective.

PURPA

Then, in 1978, Congress passed the Public Utility Regulatory Policies Act (PURPA). PURPA was established for two reasons. The first was to encourage conservation of energy. The second was to decrease dependence on foreign oil. FERC was given responsiblity to oversee PURPA compliance.

The intent of PURPA was to promote private development of underutilized energy resources, including biomass, cogeneration, and renewable resources. PURPA also directed utilities who owned transmission lines to provide interconnection to private developers, thus allowing developers a relatively cheap method of transporting energy to a regional market.

The FERC regulations, pursuant to the Act, also stated that small-scale hydro producers would receive "full avoided cost" for their produced power. FERC defines avoided cost as "the cost to an electric utility of energy or capacity or both which...the electric utility would generate or construct itself or purchase from another source." By this, major utilities were required to purchase small hydro-produced power at the same rate that would otherwise be paid if it were purchased from the regional power grid or newly developed resources. Since many small-scale hydro sites could produce energy at less than full market value, the avoided cost regulation became an incentive to developers.

LICENSE EXEMPTION PROVISIONS

The power marketing provisions of PURPA were not the only development incentive provided by this act. Within PURPA was established a new category of nonfederal hydroelectric projects - exemptions from licensing - for small hydro projects of 15 or less MW (megawatts) at a structure built for another purpose such as an irrigation or flood control device. The Energy Security Act of 1980 amended PURPA to extend the exemption procedures to hydroelectric projects of 5 or less MW at existing dams or by utilizing natural water features. The purpose of broadening the exemption process was to encourage revitalization of the older hydromechanical and, in some cases, hydroelectric facilities at small dams, primarily in the Northeast.

FERC subsequently defined "natural water features" as a diversion structure (dam) less than 10 feet in height. Originally, "natural water feature" was meant to be interpreted as a site with a high vertical drop requiring a diversion structure and tunnel (mostly underground, though not necessarily) as opposed to a dam, which is usually built in low vertical drop reaches. Some believe that this ruling by FERC, more than any other incentive, lead to the proliferation of filings for exemption from licensing for the building of small-scale hydro on Northwest rivers and streams.

DEVELOPMENT ASSISTANCE MANUALS

Other agencies of the federal government actively support the reborn small hydro industry through the promulgation of development manuals. Both the Corps of Engineers and the Bureau of Reclamation prepared detailed manuals to assist new developers in the assessment of small hydro sites. Also, the Corps of Engineers established a computer data base of site-specific hydro data.

TAX CREDITS

Congress passed the Crude Oil Windfall Profit Tax Act of 1980, creating an 11% energy tax credit. A 10% investment tax credit was also enacted to stimulate private capital investment in equipment and machinery for renewable energy projects.

Congress proved accelerated depreciation schedules to encourage capital expenditures in many industries, including small hydropower facilities, by provision of the Economic Recovery Tax act of 1981 and the Tax Equity and Fiscal Responsibility Act of 1982.

State governments followed suit, supporting small-scale energy development by providing parallel tax incentive programs. Oregon, for example, provided a business energy tax credit policy allowing a 35% tax credit over a five-year period (10% in year one and year two; 5% in each remaining years three through five). The tax credit and depreciation programs were specifically designed to attract private capital to the renewable energy market.

ENERGY LOAN PROGRAMS

The U.S. Department of Energy administered a national loan program to fund feasibility studies for hydropower development. A sum of $1,092,500 in loans was provided in the Northwest region to conduct feasibility studies for 34 proposed sites with a combined capacity of 103.144 megawatts. These funds are being repaid with interest by developers implementing the projects. The availability of these low interest funds further encouraged the potential small hydro developer. Additional funding of programs to implement technology and research and development of hydropower facilities identified hydropower as a technology offering a viable alternative for cost-effective resource development.

Corollary programs were developed at the state level to fund both feasibility studies and construction of renewable energy resources.

The people of the State of Oregon created, by initiative, in 1979 the Small Scale Energy Loan Program (SELP) which is admistered by the Oregon Department of Energy with oversight from the Oregon Legislature. The program, using the State's bonding authority, has provided more than $65 million for hydropower development since its inception in 1981. The program additionally provides loans for other alternative renewable resource industries, including conservation and solar development.

NORTHWEST POWER ACT

The Pacific Northwest Electric Power Planning and Conservation Act (the Act) of 1980, altered the institutional arrangements in the region for developing, financing, and marketing electric power, increasing the number of options available to sponsors of generating resources. The Act provided mechanisms for sharing risks and costs of new generation and conservation programs on a region-wide basis. The Act prioritized the development of conservation and renewable resources above thermal generation facilities.

Corresponding legislative actions were taken at the state level to promote renewable resource development.

NORTHWEST POWER PLANNING COUNCIL MANDATE

The Northwest Power Planning Council was created on April 28, 1981, in accordance with the Pacific Northwest Electric Power Planning and Conservation Act. The Council is an interstate compact agency, not an agency of the United States Government. The "Act" became effective when it was signed into law by President Carter on December 5, 1980. This ended a four-year debate over legislation designed to plan and coordinate the region's energy future. The Council, tasked with developing the "Plan", gave highest priority to cost-effective conservation by treating it as a resource preferable to all other means of responding to demand for electricity. Renewable sources of energy were given the next highest priority in the region's power planning ranking ahead of all conventional thermal generating resources. In its original form, the "Act" defines "renewable resource" as a resource which utilizes solar, wind, hydro, geothermal, biomass or similar sources of energy and which either is used for electric power generation or will reduce the electric power requirements of a consumer, including the direct application. This priority given to hydro development acted as a further incentive.

THE REGIONAL NEED FOR POWER

The Bonneville Power Administration (BPA), the regional marketing agency for electric power, advised its preference customers under a "Notice of Insufficiency" in 1979 that BPA would no longer be able to meet its customers' firm energy requirements after July 1, 1983.

The preference customers would have been responsible for developing new generating resources or conservation programs to meet their service requirements beyond those which would be available from BPA.

In some cases, utilities and cooperatives actively pursued develment of small hydro sites as an alternative to developing other new generating resources or conservation programs. As an example, the Pacific Northwest Generating Co., Inc., an association of REA electric cooperatives, requisitioned a reconnaissance survey of small hydro sites available in the Northwest and subsequently approached site owners to establish a mechanism for jointly developing hydropower resources.

Other utilities, both private and public, sought to develop their own resources to meet their electrical requirements by filing with the FERC for hydropower sites within their service areas and systems. A sizeable portion of capacity represented in the FERC applications in the Northwest result from applications proposing hydropower development to meet the internal resource needs of utilities who are not qualifying facilities requiring the benefits of the PURPA Act to generate and market hydropower.

PUBLIC OPINION

Public opinion actively supported renewable resources beginning in the late 1970's. As an example, Oregon residents have strongly endorsed renewable resource development as the preferred energy alternative. In a study commissioned by the Oregon Department of Energy and conducted by the Oregon State University, the following opinions were expressed by Oregonians in a May, 1984, summary:

-- 88% of those interviewed preferred renewable resource development and conservation to meet future energy needs.

-- Renewable resources were favored as the first choice (49%) over conservation (39%).

-- A significant number of respondents were willing to pay as much as a 20% premium on today's energy bills to develop renewable resources for the future.

THE FACTS ON PROJECT NUMBERS

It is our understanding that this hearing was partially proposed because of the concern for protecting the environment given the gross numbers of permits and applications for all hydroelectric projects submitted to the Federal Energy Regulatory Commission (FERC) since the enactment of PURPA by the Congress. Of further concern, though not directly voiced, appears to be the position of certain Eastern and Southwestern utilities which, caused by PURPA to purchase the resultant energy production from small power producers and cogenerators, still seek to regain a perceived element of "lost control" or "lost profits" by removal of PURPA.

Table 1 was included in a letter to Senator James McClure from the Washington State Energy Office dated May 16, 1986. It gives a breakdown of the 18 projects, both by sponsor and by project type, of note only four projects are run-of-the-river. Nine projects are private-developer sponsored while the other nine are municipally owned. Therefore, by using the Washington State example, any recission of PURPA based purely upon numeric quantification would not seem to resolve entirely the environmental impact question since those projects which are either municipally or utility sponsored apparently would still go forward.

Table 2, developed by NSHA, details the specific numbers of small hydroelectric projects under construction or built in the Northwest

Table 1

On-Line or Under Construction Small Scale Hydropower Projects Since 1980, Washington State

	Project Name	Sponsor	Purchasing Utility	Project Type	Generating Capacity, kW
1.	Russell Smith	S. Columbia Basin Irrigation Dist. (SCBID)	SCL/TCL	I	6,200
2.	Port Townsend Mill	Crown Zellerbach Corp.	PSP & L	M	375
3.	Woods Creek	Woods Creek, Inc.	Sno. Co. PUD	R	650
4.	Smith Creek	Robert Shipp	PSP & L	N	120
5.	Mill Creek	L. Walker/Lewis County PUD	Lewis Co. PUD	N	600
6.	Eltopia Branch Canal	SCBID	SCL/TCL	I	2,200
7.	P.E.C 66	SCBID	SCL/TCL	I	2,400
8.	Quincy Chute	Quincy Columbia Basin Irrigation Dist.	Grant Co. PUD	I	9,400
9.	Deep Creek	Gordon Foster	WWP	R	270
10.	Bellingham Water Supply Pipeline	Robert Shipp	PSP & L	M	900
11.	Upriver Dam	City of Spokane	WWP	E	13,100
12.	Cowiche	Yakima-Tieton Irrigation Dist.	PP & L	I	1,500
13.	Orchard Avenue	Yakima-Tieton Irrigation Dist.	PP& L	I	1,450
14.	Rocky Brook Creek	Joe Clarkson, Weatherly Associates	SCL	N	1,850
15.	Lilliwaup Falls	John Craft	Mason Co. PUD	E	1,505
16.	Main Canal Headworks	SCBID	SCL/TCL	I	26,000
17.	Big Sheep Creek	Glenn Phillips	WWP	N	1,500
18.	Falls Creek	Gus Haley	Clallam Co. PUD	R	200
				TOTAL	70,220

Purchasing Utility Code

SCL/TCL: Seattle & Tacoma City Light Depts.
PSP & L: Puget Sound Power & Light Co.
WWP: Washington Water Power Co.
PP & L: Pacific Power & Light

Project Type

Code: I = Irrigation dam, drop structure or wasteway
M = Municipal or industrial water supply conduit
E = Expansion of existing power dam
R = Refurbishment of abandoned site
N = New high head run-of-the-river project

TABLE 2

NORTHWEST SMALL HYDROELECTRIC PROJECTS*
(UNDER 30 MW - BUILT AS OF PURPA INCEPTION)

	Number		Megawatts	Total
Idaho	80	↑		
	85	27	10.533	10.533
	(Number at existing dams unknown)			
Montana	83	3	.373	
	84	1	.260	
	85	2	1.265	1.898
		6		
	(3 at existing dams, 1.505 MW)			
Oregon	82	1	19.6	
	84	5	17.231	
	85	4	7.785	44.616
		10		
	(9 at existing dams, 40.516 MW)			
Washington	80	↑		
	85	18	70.220	70.220
		18		
	(14 at existing dams, 66.150 MW)			
Totals		61		127.27

* As received from the respective State Energy Offices and Public Utility Commissions week ending May 30, 1986

since PURPA was adopted. We have indicated, where available, the numbers of projects proposed at existing dams. The project numbers in this table, in our estimation, certainly provide ample evidence that the existing and in-place environmental and economic project constraints are more than adequate and appropriate filter mechanisms to prevent the "Gold Rush" of applications from becoming project reality. It remains a relatively simple exercise to file a preliminary permit with the FERC, but it is another matter entirely to take that filing all the way to an active and operating project. In Washington State, with over 700 filings (taking into account the competitive filings), only 18 or so active projects have resulted to date.

Most assuredly the grossness of permit filing numbers nationally would give cause for concern to just about anyone. Now, however, with the factual evidence of the past two years refuting most of the perceived claims of prospective environmental damage, we are still finding environmental groups and agencies reacting as if every single application was another Grand Coulee. NSHA has, since 1982, consistently pointed out the fallacies of using permit numbers as hard evidence of prospective completed projects.

Figures 1 and 2 depict the Northwest electric balance and load growth rates. Both figures indicate near-term regional surplusses, which may well give rise to thoughts of, "We don't need any more power!". The realities are that some individual Northwest utilities are experiencing deficits currently and are engaged in developing new resources, including active discussions with BC Hydro to import hydro-

Figure 1

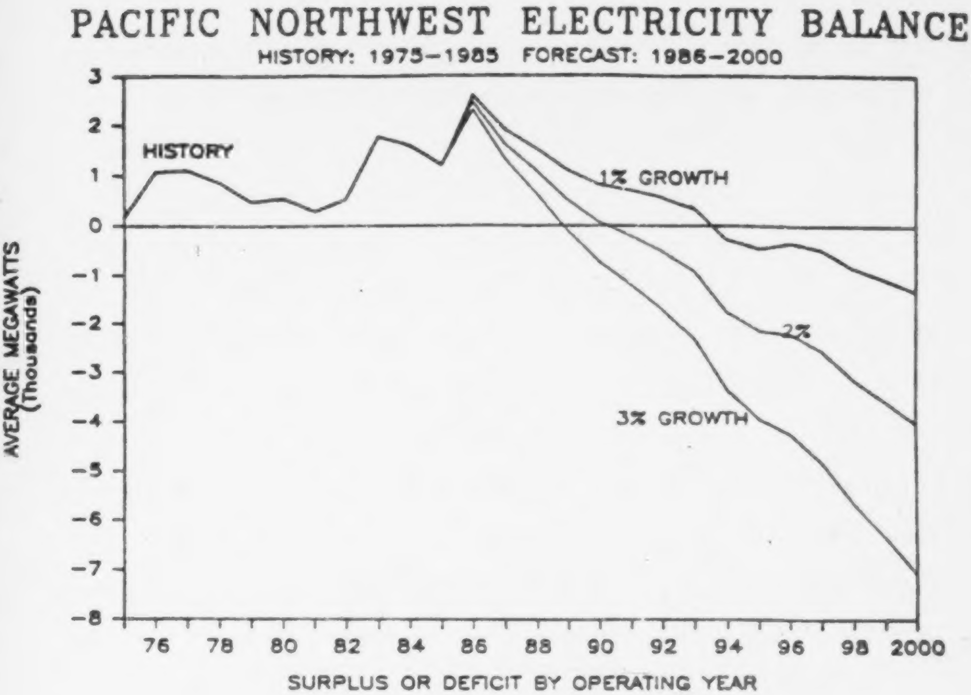
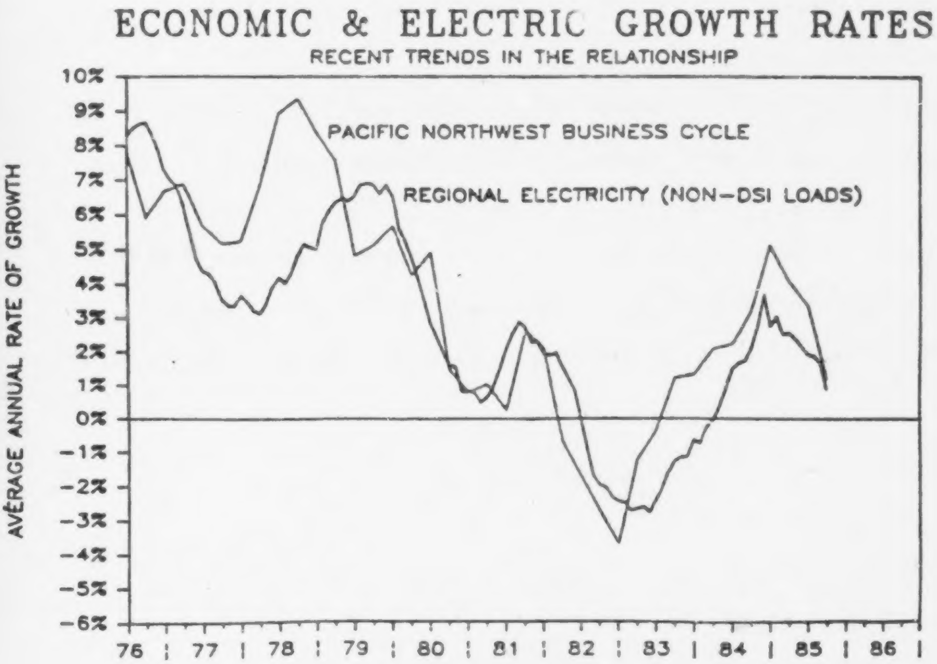


Figure 2



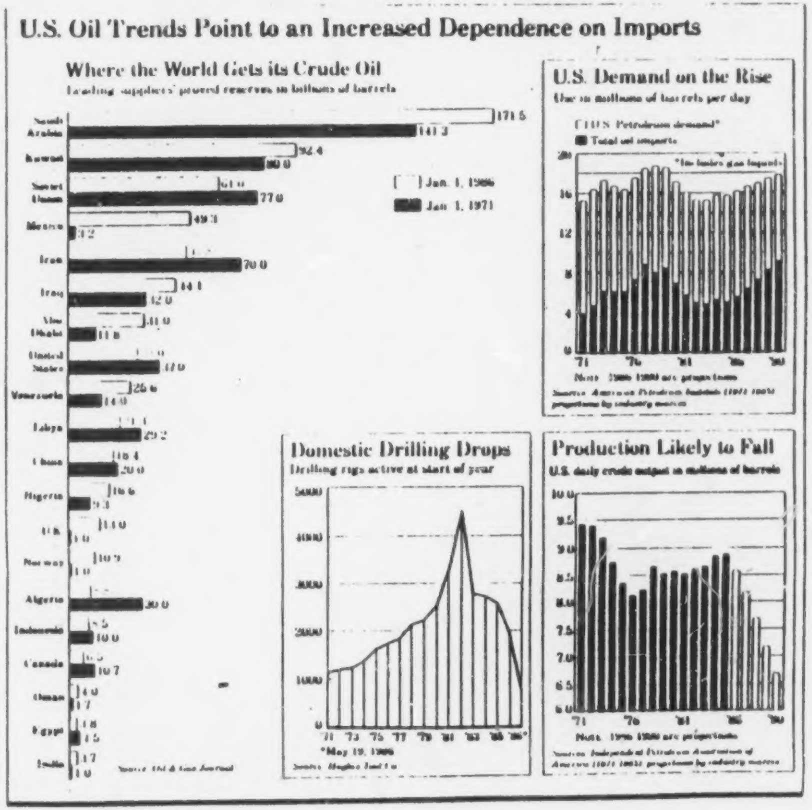
Electric Loads Are Adjusted for Weather

electric power from the proposed 900 MW dam on the Peace River. The region, as a whole, depending upon growth, could experience deficits as early as 1988.

NSHA believes strongly that the region should not be lulled into a false sense of security by virtue of the present surplus situation and lower foreign oil prices, but should continue to plan for incremental small power additions where appropriate, and most certainly from in the Northwest. History, it seems, has a wayof repeating itself, as evidenced by the content of the attached recent WALL STREET JOURNAL article, which shows that, once again, the United States has embarked upon an expanding reliance on foreign oil and natural gas.

How soon we forget the attitudes of the shieks and of the Canadian natural gas producers and their devastating price increases of the mid-1970's!

Energy Replay: U.S. Oil Imports May Soon Climb Again



U.S. Oil Trends Point to an Increased Dependence on Imports

Where the World Gets its Crude Oil

Leading suppliers' proved reserves in billions of barrels

Source: Oil & Gas Journal

U.S. Demand on the Rise

Use in millions of barrels per day

*Includes gas liquids

Note: 1986-1990 are projections

Source: American Petroleum Institute (1971-1985); projections by industry sources

Domestic Drilling Drops

Drilling rigs active at start of year

*May 19, 1986

Source: Hughes Tool Co.

Production Likely to Fall

U.S. daily crude output in millions of barrels

Note: 1986-1990 are projections

Source: Independent Petroleum Association of America (1971-1985); projections by industry sources

Saudi Arabia
171.5
141.3
Kuwait
92.4
80.0
Soviet Union
61.0
77.0
Mexico
49.3
3.2
Iran
70.0
Iraq
44.1
32.0
Abu Dhabi
31.0
11.8
United States
47.0
Venezuela
25.6
14.0
Libya
29.2
China
18.4
20.0
Nigeria
16.6
9.3
U.K.
13.0
1.0
Norway
10.9
1.0
Algeria
30.0
Indonesia
8.5
10.0
Canada
10.7
Oman
4.0
1.7
Egypt
3.8
4.5
India
3.7
1.0
Jan. 1, 1986
Jan. 1, 1971
U.S. Petroleum demand*
Total oil imports
20
16
12
8
4
0
'71
'76
'81
'86
'90
5000
4000
3000
2000
1000
0
'71
'73
'75
'77
'79
'81
'83
'85
'86*
10.0
9.5
9.0
8.5
8.0
7.5
7.0
6.5
6.0
'71
'76
'81
'86
'90

ROLE OF PURPA

PURPA RATIONALE

PURPA was introduced in the "History of Small Hydropower" section of this testimony, but, given its central nature in this hearing, it is discussed in more detail here. In particular, the role of PURPA, as an effective market incentive, is addressed.

The Public Utilities Regulatory Policies Act of 1978 (PURPA) was a response by President Carter and the U.S. Congress to the concern that present national electrical energy policy was not sufficiently protecting national security. The concern was two-fold: first, that reliance on thermal generation, particularly the use of imported oil, made the U.S. subject to disruption during periods of international tension; second, that the continued construction of the large power stations typical of thermal generation made the U.S. electrical grid more subject to interruption through acts of war or sabotage. Also, there was a consensus that alternatives to large thermal resources would provide environmental benefits.

The response of the President and the Congress to this threat was simple and quite consistent with national economic philosophy. They passed and signed into law PURPA, which attempted to create a free market where one had not existed for many years, in the electrical generation field. Public utilities were directed to calculate their "avoided cost" of energy, that cost which best represented the current incremental energy costs of each utility, considering planned new resources, load growth, resale potential and other factors as might be pertinent. Each utility was directed to offer this energy rate to developers of qualifying facilities, those projects such as small hydro, solar, biomass, wind, geothermal and cogeneration, the development of which Congress felt to be in the national interest. Purchase of generation from these resources by the utilities would then defer the construction of the large thermal stations Congress felt to be less beneficial to the nation.

SIGNIFICANT CHARACTERISTICS OF PURPA

Before examining the results of PURPA, several points should be made about the original legislation. First, PURPA required the payment of the full avoided cost to qualifying facilities, not some arbitrary percentage of avoided cost. Thus, the electric consumer was not to benefit from the development of alternative resources. Instead Congress indicated that these alternative resources were of such importance to the nation that no alternative resources were to be precluded solely for the economic benefit of the consumer. Conversely, it was intended that no additional costs go to the ratepayer as a result of PURPA, again as evidenced by the mandate of exactly the calculated avoided cost. (However, it was noted in the "History of Small Hydropower" section that a significant number of Oregon citizens would be willing to pay higher energy rates in exchange for increased reliance on renewable resources.) This approach toward the economic welfare of the consumer was referred to throughout PURPA as "equitable," a description that is reasonable and fair.

Second, no reductions in environmental or regulatory constraints were mandated by PURPA. The clear intention of Congress was that qualifying facilities only be developed if consistent with the appropriate laws and regulations.

Finally, the exact methodology for calculating avoided cost was left undefined by PURPA. It was recognized by Congress that each region had developed different strategies for meeting load growth and that the free-market concept of PURPA would only be met if each state had the flexibility to calculate avoided cost based upon those regional strategies. Thus, with the exception of general guidelines, PURPA allows complete flexbility to each state on the avoided cost calculations.

PURPA IMPLEMENTATION

The implementation of PURPA in the Pacific Northwest has been moderately successful, but flawed in some areas. It must be noted, however, that the region has been in an electrical surplus virtually since the effective date of PURPA. Therefore, the two primary tests of PURPA effectiveness - the ability to bring on-line a large number of qualifying facilities to meet load growth and the successful supplanting of large thermal power stations - have not been completed. Despite the inadequacy of the PURPA trial thus far, there have been some small hydro qualifying facilities brought on-line, with a combined capacity of 127 megawatts, less than one percent of the total regional load. Although many of the power sale contracts negotiated for these projects are not strictly based on PURPA guidelines or avoided costs, virtually all were initiated through the PURPA process. It has become common for a utility and a developer to begin negotiations under a strict PURPA format, then to evolve to another contractual form that offers more mutual benefits. This process, which is highly desirable, must be considered a success of the PURPA concept.

Despite these successes, there have also been glaring failures of the PURPA process, all of which result from circumstances beyond the scope of the Act. First, it was quickly discovered that the setting of avoided costs is a complex and subjective undertaking. Avoided costs in the Northwest have fallen abruptly since 1982, in large part justifiably because of the electrical surplus, but also, in some part, unjustifiably because of changing political perceptions of qualifying facilities. While it was the intent of Congress to expose the development community to the risk of changing power economics, it was not the intention to include exposure to risk from changing political moods. This latter risk has damaged the industry, inducing qualified and enthusiastic developers to abandon viable projects and reducing the ability of the qualifying facility industry to meet load growth. Second, the sharp dichotomy in the Northwest between publicly-owned and investor-owned utilities has resulted in marketplace inequities.

The predominant regional publicly-owned utility, the Bonneville Power Administration, has yet to accede to PURPA jurisdiction and, therefore, has never established avoided costs. In turn, the smaller public utilities that receive wholesale power from BPA have quoted the wholesale rate, now at 22 mills, as their avoided cost. In contrast, the investor-owned utilities at one time published avoided costs as high as 90 mills before returning to levels currently near 30 mills. As a result of the wide disparity in rates that existed for a couple of years, projects that were less desirable from economic and environmental perspectives, but which were located in the service area of an investor-owned utility, were built before more desirable projects located in the service area of publicly-owned utilities. This situation has no legitimate jusification and is the result solely of arbitrary utility borders and a flaw in PURPA.

SUMMARY

To summarize, PURPA was a laudable attempt to address undesirable characteristics in electrical power planning. To date in the Northwest, implementation has been moderately successful but has not been fully tested due to the regional surplus. Nonetheless, flaws in the Act have been noted.

PRESENT SMALL HYDROELECTRIC ENVIRONMENTAL PROCESSES

Of the power generation resources available for development, hydropower is generally accepted as being one of the oldest and lowest in energy cost. In the mid-1800's, in the East, power derived from falling water was used to generate shaft horsepower for mill operations. As generator technology improved, many of those same mills were converted to electric power plants. By the 1890's, hydropower generated electricity was the primary form of electrical power generation.

While technological advances have occurred in water turbine and generator design, the basic tenets of both hydraulic engineering and civil engineering design have remained as they were in the 1890's. Industry has improved the efficiencies of turbine prime movers, and in recent years, with advances in insulation and bearing technology, generators have been improved to increase power output. Today, with the advent of computers and logic control, systems are available and in use to run hydro plants automatically thereby greatly decreasing manpower requirements and operational costs.

With almost 100 years of industry experience, the hydroelectric power generation plant has the most refined technology of the renewables field. The modern hydroelectric plant has no fuel cost, and its annual maintenance expense is one of the lowest of comparable generating resources.

EXISTING LICENSING PROCESS

Admittedly, the historical environmental record for hydroelectric development has not been good, particularly with respect to fisheries protection on the projects of the Columbia Basin and other major projects elsewhere. There is definitely not a corresponding situation with present small hydro development. Past reasons for problematic environmental outcome have included a lack of good scientific information during project design and a historic bias on the part of the FERC to license almost every application for hydroelectric development. This clearly has not been the case over the past two years. FERC licensing requirements in the environmental area now have become, and properly so, much more stringent. The FERC has denied licenses and exemptions and has delayed licensing and exempting large numbers of projects pending unresolved environmental issues, or perceived public opinion.

It would not be possible today to obtain federal licenses for the vast majority of existing large hydroelectric projects, including those of the Columbia River Basin. Even small, run-of-the-river projects are subjected to such increased environmental scrutiny under the newest FERC rules that it is only those with a "no net loss" or a "net gain" assessment that a license would be granted, and then only with agency support letters in the Northwest. It is becoming fair to say that a FERC license will be granted only with proper environmental design and the support or approval of local agencies and Indian tribes.

Conservative estimates indicate that we should expect a steady decrease in project filings as well as the wholesale abandonment of existing and proposed preliminary permits. We should, therefore, continue to allow the economic factors as well as the environmental study and design cost to be the ultimate arbitrators. After all, a hydro project which is not economic today sure as hell isn't going to be any more economic ten years from now - inflation has a way of securing that fact.

We are now starting to see, at the preliminary permit study phase of development, much more realistic assessment of the economic and environmental viability of individual projects. It is our belief that, through these investigative processes, only about 10-15% of new preliminary permitted study projects will advance through to the next stage of feasibility assessment.

Most developers look for two key characteristics for developing sites. These are:

1. An existing dam or irrigation facility.
2. A natural feature site which has anadromous fish barriers downstream of its development or projects which reside in areas of marginal to negative anadromous fish habitat.

Each site must, at its reconnaissance level of study, be capable of supporting, with adequate ROI, a sometimes lengthy power interconnection service as well as an appropriate hydrologic flow regimen which accounts for instream flow requirements and which fits seasonally into a region's power markets. If projects do not fit within this reconnaisance feasibility assessment, they are quickly dropped. No developer, no prudent developer, either public or private, is anxious to spend risk dollars for further definition of a given project if it does not pass the first cut of economic and environmental assessment. Those permit projects which do fit move into the next stage of feasibility and potential development and then advance through the varying study phases of the license process.

It is at this stage that cogent agency involvement begins. It is at this stage where the prudent developer works with the respective fish and wildlife agencies and water quality agencies to determine the additional fatal flaws of a potential resource site. With this agency and tribal assistance, potential environmental problem areas are identified; the timing and degree of study to gather additional information is worked out, with the intent of measuring each and every potential impact area. In full concert with the agencies and tribal interests, the cost of mitigation for each impact is generically assessed upon the project; its developer can then decide whether it is appropriate to continue studies toward development or whether to drop that particular resource from the inventory.

Thus far, we have concentrated essentially upon the fisheries impact. Among the other studies which would be conducted on any given site are those concerning the hydrologic regimen and water quality, geologic and soil assessments, fish and wildlife habitat, migration patterns, flight paths, benthic community assessments and impacts, vegetation and microclimatic concerns, health and safety, socio-economic impacts, Indian fishing rights and cultural impacts, aesthetics and noise, recreational resource availability, open space resource quality as well as energy supply market potential and many others. Among the first assessments a project developer will conduct is the identification of applicable statutes and administrative regulations that a given project falls under. Some which have to be considered in the small hydro area are, at the federal level, the Wild and Scenic Rivers Act, the Endangered Species Act, the Federal Power Act, Coastal Zone Management Act, the Rivers and Harbors Act of 1899, the Federal Energy Regulatory Commission (FERC), the Public Utility Regulatory Policies Act (PURPA), the Federal Land Policy Management Act, the National Forest Management Act, the National Environmental Policy Act, the Fish and Wildlife Coordination Act, the Historic Preservation Act, the Wilderness Act, the Clean Water Act, the Archaeological Resources Protection Act and the American Indian Religious Freedom Act.

It is our belief that the number of regulatory programs currently in effect more than adequately protect both the environment and the public interest.

A developer will work with the following federal agencies either in a license, permit or negotiation phase, as follows: National Marine Fisheries Service, the Environmental Protection Agency, Corps of Engineers, the Department of the Interior including the U.S. Fish and Wildlife Service, the Environmental Division, the Bureau of Land Management, National Park Service, the Bureau of Indian Affairs; the

United States Department of Transportation, including the Federal Highway System and the United States Coast Guard, the Federal Aeronautics Administration, the Federal Communications Commission, the United States Department of Agriculture, including the United States Forest Service and the Soil Conservation Service.

At the state level, a developer will work with the state planning authorities and energy siting facilities commissions, the Departments of Natural Resources, the Department of Fisheries, Department of Game, Historic Preservation Office, the Parks and Recreation Departments, the PUC's and/or utilities and Transportation Commissions, the State Water Departments, (in Washington, the Department of Ecology) and State Economic Development Departments. In fact, in the State of Washington, a developer may well work with some 47 federal, state and local agencies to arrive at a series of enabling permits, licenses and hydraulic permits and water rights capabilities. This does not include public involvement which, by obtaining certain permits and licenses, and media advertising, will effectively bring into the consultation process interested public parties and other federal, state and local entities which have interest in the development of a given project. Since the Bolt 2 Decision, there has been a great degree of effort with respect to Native American and Indian fishing rights, and no Pacific Northwest developer who is progressing through an appropriate development phase will forget to include the tribal interests in his projects development.

As a project advances through its design phase to construction, the County Planning Departments and local governments will require involvement, consultation and completed design drawings to grant Shoreline Substantial Development Permits and variances, Conditional Use Permits, State Environmental Policy Act compliance, surface water drainage plans, grading permits, right of way permits and finally, the building permit.

During the licensing and permitting processes, concerned federal and state agencies have the opportunity to involve themselves in a hydro project at least three to four times, and their inputs and agreements must be considered for a project to advance through its construction phase. No project developer is going to risk a project's souring because of lack of agency contact and compliance with its wishes.

The system, as it currently stands, works and most assuredly requires no additional levels of involvement.

CUMULATIVE IMPACTS

The concept that development of multiple hydroelectric projects could create cumulative environmental impacts was first discussed by environmental resource agencies in the early 1980's, and was raised officially with respect to small hydro development in the spring of 1983. The notion made intuitive sense, but unfortunately no one raising the issue could recommend a methodology or process for identifying the impacts. In the Northwest, the issue was brought before the FERC, the Northwest Power Planning Council and, finally, Congressional representatives.

Agencies and tribes overseeing regulation of hydroelectric development in the Snohomish Basin of Washington State have opted for a sequential development approach much more akin to the historic case-by-case approach to licensing. The critical difference is that more information is collected, sufficient to identify potential project specific impacts using state-of-the-art techniques. Each project analysis is required to take into account environmental effects of projects which are existing or would be built first, and to include monitoring of project impacts with contingency operation plans. Although disputes may develop over the study information to be collected and interpretation of results, this approach has proven to be a practical one, placing the burden of proof on the developer and not overly burdensome to any particular agency.

Again, the existing FERC process, if carried out effectively, is sufficient to identify project impacts, taking into account the effects of other developments existing and proposed, and effect decisions in the public interest. This was the case for the Weeks and Twin Falls Projects and is the premise behind ongoing study of several other projects in the Snohomish Basin and in Washington State.

CHOICES

It must be recognized that a position of opposition to small hydro development in the Northwest in favor of protection of the fishery resource and aesthetic values is not a choice which can be made in a vacuum. It also represents a clear choice to pursue other energy options. Most of those options have negative environmental and economic aspects which rival or exceed those of small hydro.

If the private developer component of the small hydro industry in the Northwest were to end due to the withdrawal of PURPA, strengthened regulatory constraints or other factors, there would be several results. First, the established small hydro community of private developers, consultants, financiers and supportive agencies would likely disband forever. Already the existing community has had defections due to disillusionment with the process. Many who became involved in small hydro development did so, due equally to the profit potential, its environmentally benign nature and to the prospect of contributing to a better national energy policy, have wearied of the time and cost of endless regulatory hurdles and have tired of the negative, and mostly uninformed, institutional portrayal typically given to small hydro. Any further pressures will likely remove the remaining vestiges of private enterprise involvement in the industry.

Without small hydro in the new resource mix, the region would have to look elsewhere to meet the inevitable load growth. Conservation has become the resource of choice of the Northwest

Power Planning Council. However, others, notably the Bonneville Power Administration and some area utilities, have lost enthusiasm for conservation, fearing both the societal changes that would be required to implement the next level of conservation measures and the environmental consequences and impacts of elements such as radon gas and other bronchial irritants and afflictions that could accumulate in energy-efficient closed-envelope structures.

The cogeneration industry may survive the current downturn, as it has not received the opprobrium directed at small hydro. However, barring numerous cogeneration developments, the remaining regional options will be the large thermal stations, coal and nuclear, originally discouraged by PURPA. In addition to the national security interests originally expressed by the Congress, may now be added the severe environmental and international concerns of acid rain from coal plants, nuclear accidents and radioactive waste disposal for nuclear plants.

A further option available to the Northwest would be increased generation at the Columbia River dams, abandoning the recently implemented fishery protection program. These, obviously, are options which would not be favorably received. Nonetheless, they and the large thermal stations are the alternatives to the demise of an effective private small hydro industry and the selection that the Congress could be making if small hydro development is further stifled.

The CHAIRMAN. Mr. Elston.

STATEMENT OF PAUL J. ELSTON, PRESIDENT, LONG LAKE ENERGY CORP.

Mr. ELSTON. Thank you, Mr. Chairman, for the opportunity to testify today. I am the president of Long Lake Energy Corp., but I am also before you today as an individual with some 10 years of dedication to environmental protection and conservation. I have served as Deputy Commissioner of the Department of Environmental Conservation in New York State, as well as an official EPA, Deputy Assistant Administrator.

Long Lake is a developer of small hydroelectric projects in New York, where we are developing some 38 projects, mostly in upstate New York. Two of the projects are operating today, one is under construction and four more are going under construction this year. The balance are tied up in the very complicated and extensive licensing process at the Federal Energy Regulatory Commission.

This company was started because of PURPA. At that time, when we looked at the bill and the results of the work of Congress, our reading was that the Congress had made the judgment that it was desirable from the public's point of view to introduce market forces in the business of producing electricity generation; that it was desirable to bring on line economically developable renewable resources; that it was desirable to pursue cogeneration because we could get more power out of a barrel of oil than by the traditional methods.

The Congress had also found that the utilities had systematically avoided competition up to that point in time. They had underpriced the purchase of electricity and they created unnecessary impediments to interconnection to the system.

We agree with the judgment of Congress at that time, and we think that those situations that initiated PURPA exist today; they have existed since the initiation of PURPA, as well as before PURPA.

In my testimony, I have provided you with some detail of what I would describe as some rather excessive anticompetition activities by the utilities in New York. In one specific incidence, we came upon a 45-megawatt development on the Hudson River, a site that is indeed a very valuable public resource.

The utility had a license on the project and had been operating in violation of that license by not operating the site for some 13 years. The condition of the facility is documented in FERC inspection reports, where the inspector would no longer go into the plant because it was infested with lice, vermin, and was otherwise a hazard.

After we filed the license to develop this site, the utility decided it was time for it to develop the site, and filed a competing license application. It took 3 years for FERC to decide that, indeed, the project should be opened up for competition, and 3 years later, the competition began anew from our point of view.

The utility not only tied up the resource and decided belatedly to invest in it, but after we filed the license and were heavy into the competition, the utility tried to coerce our corporation to withdraw from the competition by threatening us with delay and non-negotiation on four other totally unrelated projects.

The situation deteriorated such that we had to go to the Public Service Commission, brief them on what was going on, and finally, and much to the credit, I think, of the Commission, they intervened and the situation has since been reversed.

I think it is just one of what I suspect are many clear examples of anticompetition activities on the part of the utilities, and in the absence of the types of protections that PURPA provides to corporations like my own, we simply would not be in existence today.

With respect to the discussions on avoided costs, I won't try to go back into what I think is a very excellent presentation by Jam Hamrin on some of the economic theory underlying avoided costs, and I think it has been thoroughly discussed today.

I think also that in fact some of the regulators that were speaking on the last panel made the point, and I want to underline it; we are paid in New York State 6 cents a kilowatt hour to produce our electricity. The utilities in New York today are bringing on electricity at 18 to 20 cents a kilowatt hour, and the ratepayers are paying for that.

These are the large, centralized nuclear plants. Everybody admits that it is a mistake. You can look back today and see that it was a mistake to have started these plants at sometime in the past. The fact of the matter is, that that is the risk that the utilities have taken in the past and it has been a very costly risk—excuse me, not the utilities, that the consumer has taken in the past, and it has been a very costly risk for the consumer that we can see today.

I think that the risk that we represent for a consumer when we are paid 6 cents a kilowatt hour is de minimus when compared to the risks that the consumers have in fact taken by the utilities going forward with these large centralized plants in the past.

As has been pointed out before, the developers in this situation only get paid if they deliver electricity. They absorb from the consumer the cost overrun risk and the risk that you build a plant and not operate it, or as has happened in New York on the Indian Point plant, that you build a plant that is designed to last 40 years and it is shut down over 20 years. The ratepayer pays for that.

If that happens to me, the ratepayer does not pay.

One of the big issues about pricing is the question of whether or not capacity is needed, and I think we all recognize that the situation varies from region to region throughout the country.

One thing is very clear. The pipeline is empty today. The number of plants that have been cancelled in this country over the last 5 to 10 years has just totally emptied the construction pipeline. The things that are coming online now leaving nothing forward in the construction pipeline.

At the same time, and we heard some discussion about this a minute ago, the planners—apparently, in Washington there was no planning. I can tell you in New York, the situation is very much the same; that the way projections are done in New York as to what the future capacity needs are is that the utility submits the numbers, and the State regulators add them up, and that is what the projections are.

Right now, on a national basis, the projects for growth and demand are roughly 1.3 percent. The numbers in New York State are larger than that; it is 1.5 per year, projected growth in peak demand. That compares with the average over the last 20 years in New York State of 2.8 percent, almost twice the growth rate of the official projections today.

The growth rate between 1984 and 1985 in New York State was 4.9 percent, almost another 50-percent increase over that. Using the 1.5 percent, the low project, the State is saying that it needs more capacity in 1996. If in fact, the 20-year historical growth rate is the reality, you are talking about 1992, a need for new capacity.

If the 4.9 percent figure is repeated in the immediate future, you are talking about running out of capacity in roughly 1988. In this business, 3 years from now is like yesterday because it takes a long time to bring these plants online.

I submit to you that several years from now, when the next round of hearings are being held, that the issue is going to be capacity; that the swings of the planners, when they were using 7 percent a few years ago and they got burned for doing it, are now using projections of 1.5 percent, and they are too low, and we are going to be looking at serious capacity shortages in the immediate future, not the far distant future.

I think it is a serious problem, not just in New York, but I think it is one across the Nation. I think it is a bad bet from the ratepayers 'point of view.

With respect to the environmental impact, first of all, I think it is important and we all recognize it, that there is no type of electricity generation that does not have a cost to our environment and to our society.

The problems vary from region to region around the country.

In New York, the total portfolio of my company and virtually all of the other developments are developments at existing dams. The reason for this is that there are plenty of them there.

Upstate New York was built around these dams when it was industrialized in the late 1800's. The dams were abandoned roughly in the 1950's when the utilities became preoccupied with the large centralized plants.

It does not make any sense, when you are faced with existing dams that need rehabilitation, that you go and build new dams. New dams are much more costly from an environmental point of view, and from my point of view as a businessman, they represent much greater risk. It was my judgment, and I think it is true in New York and elsewhere, that my ability to build a new dam in New York State, if I wanted to and I don't, but my ability to do that is almost nil.

The regulators would not stand for it; the environmental community would not stand for it. It would just never happen, and if for some reason it did happen, it would take forever. It is a bad business risk to build new dams and it is not happening.

What is happening, unfortunately, is, on FERC's part, because FERC has beaten up by the environmentalists and in some cases, in some hearings here in Congress, on their recognition and response to the environmental concerns, is what I consider an over reaction.

You have a number of cases where, after having come to resolution of all of our environmental problems, with the State agencies and everyone else involved, because one individual decided that he wanted to do some kayaking on the river, even though the issues had been before by all of the regulatory agencies, FERC shut down our process and delayed our development because there was one objection which we considered and I think fairly can be considered belated and irresponsible and had been fully heard prior to that point in time.

It is what I describe as an overreaction on FERC's part that has led to some mischief.

In summary, I would say, yes, there are some problems with FERC, and we have heard a lot about them. We have heard a lot of solutions that I think are very sophisticated, they vary from region to region. The nature of the problems are not one that require legislative change.

They are problems that are implementation problems and it appears to me that FERC presents adequate flexibility for dealing with them in a rather systematic way.

In fact, a new set of legislative changes at this stage of the game would simply create yet another set of implementation problems that we would be back in talking about. I think you have a good thing going here. It is working well and should be left alone.

I think there is a need to tighten up the enforcement by FERC. They should not be allowing plants to be operated or not operated for 13 years in violation of their license without any penalty on the licensee, after that performance.

I think that we are going to have a serious problem on our capacity question, and there needs to be some serious attention paid to upgrading our ability to project what kind of capacity that we are going to need in the future, and, finally, I think it is very important that we recognize that there are regional differences here, and I think we have in place a mechanism that allows each region—each State—to deal very effectively with the issues in their area.

Thank you, Mr. Chairman.

[The prepared statement of Mr. Elston follows:]

TESTIMONY BEFORE THE
UNITED STATE SENATE COMMITTEE
ON ENERGY AND NATURAL RESOURCES
REGARDING
IMPLEMENTATION OF
THE PUBLIC UTILITIES REGULATORY POLICY ACT OF 1978

SUBMITTED BY

PAUL J. ELSTON, PRESIDENT
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JUNE 5, 1986

Mr. Chairman and Members of the Committee, thank you for inviting me to testify on behalf of Long Lake Energy Corporation at this oversight hearing on PURPA. Long Lake is a private company engaged in the development, construction and operation of small hydroelectric projects. The focus of our efforts has been upstate New York. Founded in 1980, the company has thirty-eight projects at various stages of development. Two are operational, a third is in the final stages of construction and four more will begin construction before the end of this year. The balance are in various stages of the complicated and extensive regulatory process at FERC.

Prior to founding Long Lake I served in environmental agencies at the state and federal levels. In 1980, when I founded this company, it was my view that there would be substantial environmental opposition, sooner or later, to building dams on free-flowing rivers. Consequently, I directed the efforts of my Company toward identifying potential at sites with existing dams. New York is blessed with a large number of such opportunities and the reasons are rooted in her industrial history. Because of the availability of mechanical water power, within a few decades of the American Revolution the Hudson Valley and the Mohawk Valley were part of a vibrant, growing industrial economy in New York State. Many of the businesses founded in the nineteenth century are still contributing to the state's economy. However, many dams were abandoned as some mills went out of business. Our company and others like it in New York have been rehabilitating the existing dams to take advantage of their power potential. This development is a direct result of PURPA. I would like to discuss four major issues of importance to small power producers in relation to PURPA.

First, with the passage of PURPA, a crack was opened for the first time in the utilities' traditional monopoly over electric power production. Prior to PURPA, there was definite evidence that utilities used their monopolies to prevent companies from entering the market.

For example, before PURPA was passed, utilities in New York had a number of contracts with paper companies to buy their excess power. In each case the utilities paid less than a penny per kwh. When the New York Public Service Commission analyzed the price utilities should be paying for electricity based on avoided cost guidelines in 1983-84, they discovered the price per kwh would have been significantly more, about 6-7¢/kwh, if they were using non-discriminatory pricing. The utilities deliberately chose to pay significantly less for the power from the paper companies in order to discourage their entry into the market.

Many utilities still continue to discourage independent power production with their monopoly power. We have had first hand experience with a utility in New York that has used their monopoly status to try to prevent us from competing with them for FERC licenses on projects. For example, in 1981 we found an existing hydro site on the Hudson River, Baker's Falls, that had about 45 megawatts of potential capacity but was under FERC license to the local utility. I say potential because the site had not operated since 1973. Contrary to FERC requirements, the license holder did not seek permission from the Commission to cease operation in 1973, they just shut down. As a result, the development has remained idle. This is what FERC's own regional engineer said about the project in his inspection reports:

- November 27, 1973: ". . . The writer was advised that Niagara Mohawk Power Corporation does not intend further generation at this plant."

- May 10, 1978: ". . . This plant is not being operated and no maintenance work is being performed at this development."

- June 20, 1983: ". . . The Bakers Falls development, inoperative since 1973, is fenced off. It was not inspected but was only viewed from outside the fence. The Licensee's people are reluctant to enter its grounds and buildings. Vegetation masks the depressions and decay weakens the wooden walkways, making the grounds treacherous; rats infest its buildings, making them possibly disease ridden; and trapped birds and animals die and rot in its buildings, making the air putrid. The licensee's health officer has instructed all Niagara Mohawk personnel not to enter the site because of a documented infestation of lice."

Only after Long Lake submitted a license application in 1981 did the existing license holder show any interest in preparing an application that would develop the full potential of the site. On May 18, 1984 the Commission gave notice that a relicensing proceeding was commenced, and issued an one-year renewable license to the existing license holder. In effect, FERC agreed that the resource had been neglected and needed redevelopment. However, it did nothing to punish the existing license holder, who had blatantly violated the terms and conditions of his license for more than a decade.

Because the utility had the license to the site, it effectively prevented anyone else from utilizing the potential of this valuable natural resource.

In addition to violating their license terms and preventing anyone else from having the the use of this renewable energy source for years, the utility has attempted to coerce Long Lake to withdraw from the competition by refusing to allow us to proceed with the development of four unrelated projects. The utility specifically refused to negotiate power purchase contracts, land acquisition, interconnection and several other essential dimensions of the developments unless we withdrew from the Baker's Fall license competition. We finally had to appeal to the Chairman of the New York Public Service Commission who was outraged at the utilities actions. After direct intervention from the PSC staff, the utility reversed its actions.

This example underscores several problems. First, some utilities are using their monopolies to tie up valuable resources and prevent other companies from bringing them back into production. Second, without PURPA, the utility would have been successful in stopping our efforts to develop these resources. Third, FERC needs to vastly improve its enforcement of the terms and conditions of the existing license and penalize those licensees who violate the terms. In blatent examples of violations such as this, the licensee should not be allowed to continue their control of a project.

In light of these examples of how utilities are trying to keep small power producers out of the electric production market, you can understand our strong support for continuation of PURPA. Without the opportunities PURPA provides for us to force the utilities to the bargaining table, we would not stand a chance to develop these resources. Therefore we urge the Committee to keep PURPA in force.

Our second issue deals with what small power producers should be paid for their power. The basis for calculating avoided cost has been called into question recently due to claims from utilities that they are paying more for power from small power producers than they should and that the consumer is being hurt in the process. The discussion of avoided cost calculation must be looked at in a realistic context.

In New York for example, utilities are bringing new power on at a levelized rate of 18-20¢/kwh for nuclear power plants. The State Energy Office estimates that new coal plants have a cost equivalent to a levelized rate of 9¢/kwh over their life. These are probably optimistic cost assumptions for the life of the plants and in the case of nuclear plants, the estimates do not include decommissioning costs.

At present, hydro facilities in New York receive 6¢/kwh, a rate that is quite competitive relative to the costs just discussed. Obviously there are uncertainties associated with projecting future avoided costs. However, the financial risks associated with the alternative - building nuclear or coal power plants - are much greater, not to mention the environmental risks associated with these technologies. The utility industry's record of cost overruns is well known.

The point that is frequently overlooked in criticisms of the "high costs" being paid to small power producers is the alternative to not paying true avoided costs. Would the rate payer be better off paying a fixed avoided cost to small power producers or taking their chances on future costs associated with large centralized power plants? We believe the risks for the consumer associated with utility built large centralized plans are much greater. We recommend that this Committee encourage state utility commissions to carefully examine alternatives for developing new capacity and the long term costs and risks to their consumer when they are pressured by utilities to reduce rates for avoided costs. The commissions should place a value on this risk assumption by the small power producer.

The third issue associated with PURPA that has been receiving a great deal of attention is the need for new electric generating capacity in the U.S. As this Committee knows from its hearings last year, there have been claims that the U.S. may not need additional generating capacity for at least 10 years or so. Although we recognize there are regional differences in the need for new generating capacity, there is no questions that the pipeline for development of major quantities of new capacity is empty at the present time. We feel that in many instances people are looking at the wrong set of numbers in relation to electricity demand. In reaction to the incorrect growth projections for peak electricity demand made a decade ago, planners have swung to the other extreme of being overly conservative in the demand projections.

For example, New York State is projecting a 1.5% growth rate in peak electricity demand. The 20 year average for peak demand growth has been 2.8% In 1984-1985 the actual growth in peak demand was 4.9%. If the 1.5% growth rate is used, the state will not need new capacity until 1997. Under the 20 year average growth rate of 2.8%, New York will need new generating capacity by 1992. If last year's growth rate continues, the state will be short in 1988. In the world of electricity production, 1988 is yesterday. Capacity estimates need to be more balanced if the state is to avoid a crisis in the future. This is true throughout the country.

In the past, planning for the addition of new capacity usually meant the addition of major increments of power from centralized power plants. Power developed under PURPA is usually in small increments. Small power producers offer electricity planners flexibility that is essential to dealing with uncertainties associated with projecting energy needs into the future. Not only do small power producers bring on small increments of power, they also put these facilities into operation with much shorter lead times than centralized power plants. In addition, the cost overrun, delay and operational efficiency risks associated with these projects are taken by the developer not the rate payer. The incentive for small power production provided by PURPA is responsible for providing this important new flexible source of electric generating capacity. In light of the uncertainties associated with energy supply and demand, small power production is a very valuable contribution to the country's ability to respond to future electricity needs.

The last issue we would like to discuss in relation to PURPA is the environmental considerations associated with hydro development. There is no question that there are different environmental concerns associated with hydro development in various regions of the country. In the West, the opposition to small scale hydro development stems from the damming of free flowing rivers. Unfortunately, a few new hydro projects on controversial sites have generated a great deal of opposition to the entire small scale hydro industry. However, the scale of the new dam problem on free flowing rivers has probably been blown out of proportion. Although a large number of permits have been filed for sites in the northwest and other areas, it is unlikely that the majority of these filings are serious possibilities for development.

In New York State there are virtually no new dams being proposed. It was clear that the opposition to the construction of new dams would make it impossible to build these projects. However, the state did make a definite decision to encourage the restoration of the large number of existing dams rather than demolish them. The reasoning behind this was that a large number of rivers in the Adirondacks were protected wild and scenic rivers that would not be developed for hydropower. Therefore, the citizens of the state would have access to free flowing rivers while the rivers developed during the early part of this century would continue to be used for their power potential.

The publicity associated with a few ill conceived projects due to environmental problems have made the

Congress question PURPA benefits and caused FERC to be gun-shy when granting new licenses. For example, even after a developer like Long Lake has secured all necessary federal and state approvals, FERC is still reluctant to act if there is any negative comment on the record. As a result, single issue oriented groups have learned that simply by objecting at any stage of the process they can slow down the licensing process. In New York, the State Department of Environmental Conservation takes the lead in defining the various environmental and recreational requirements for a developer. In some cases, these interests collide. What is preferable from a fisheries point of view may not be ideal for a white water canoeist. So if the whitewater canoeists don't get everything they want from the State, they take their case to the Department of Interior and ultimately to the environmental staff at FERC. The only thing wrong with this is that there is no discrimination by FERC between responsible comments from environmental groups, and those from special interest splinter groups. In some cases these splinter groups may even go against the interests of the larger environmental community. For example, Long Lake has negotiated an environmental package acceptable to all parties and approved by the State, only to have that package undermined by one party or another at a later stage. We have experienced delays in our licensing procedures because of comments filed past filing deadlines, and on grounds already dismissed by the state Department of Environmental Conservation and FERC.

We feel both federal and state government agencies should carefully consider environmental concerns related to hydro projects. Blatent cases of severe environmental damages caused by hydro projects should and will be stopped by the regulatory process. However, FERC and the States should learn to differentiate between responsible comments and small special interest comments. In particular, everyone should be bound by the same filing deadlines for comments and the other rules associated with processing permits and licenses.

In summary, we feel that PURPA should not be modified. Competition in electricity generation is good for the ratepayer and the nation. Without PURPA there will be no chance for competition. The problems raised by these hearings result from imperfect implementation of the law and do not require a legislative solution. PURPA has the flexibility to respond to the specific needs of each state. Any efforts to solve these problems on a national level would overlook the need to find regional solutions to various electric generation issues associated with PURPA. This flexibility should continue. If Congress were to make legislative changes in PURPA it would only start a whole new round of implementation problems. Instead, we hope this Committee will provide specific recommendations to FERC and state public utility commissions to solve present problems with PURPA.

We recommend that the Committee tighten up their oversight of FERC's enforcement of PURPA. This will solve many environmental problems and violations of existing license conditions. Second, a thorough analysis of electric generating capacity and the potential cost of various sources should be completed so that policy makers and planners will be in a position to meet future energy needs in a flexible way. Third, some mechanism should be established to balance regional surpluses and shortages of electricity such as through wheeling or some other means.

We appreciate the opportunity to present our views on PURPA and would be happy to respond to any questions the Committee might have.

The CHAIRMAN. Thank you.
Mr. Conrad.

STATEMENT OF DAVID R. CONRAD, WATER RESOURCES SPECIALIST, FRIENDS OF THE EARTH

Mr. CONRAD. My name is David Conrad. I work as a water resources specialist with Friends of the Earth, a national conservation organization, and I live here in Washington, DC.

I appreciate the opportunity to present testimony and would note that today my testimony is submitted on behalf also of the Izaak Walton League, the National Audubon Society, and Trout Unlimited.

Mr. Chairman, the issues which I want to touch on are not completely new to the committee because they were touched upon in hearings on the relicensing bill last year, but all the PURPA-promoted technologies, I believe it is fair to say that the greatest potential for environmental harm, at least in the current climate, would involve hydroelectric power projects, particularly involving new dam or diversion.

It was National Environmental Organization's belief that when PURPA was originally passed, that the intention was to promote technologies that would result in relatively few negative environmental impacts, and that Congress had made the distinction between new and existing dams in PURPA.

As a matter of fact, the Conference Report—I won't read much of this—but the Conference Report had a provision that said the conferees intend that water be included within the meaning of the term "renewable resources," with respect to hydroelectric facilities at existing dams.

Now, that was largely, I think, because the whole PURPA debate whenever it entered into the hydroelectric arena, recognized or focused upon the retrofitting of existing dams, and yet, in 1980, when the FERC instituted its rules regarding the implementation of PURPA it dissolved the distinction between existing and new dams and has, I believe since, caused considerable difficulties for the environmental community in maintaining its unfettered support for the PURPA Program.

In doing that, the Commission had an economic analysis that said that by reinterpreting congressional intent, that there would be no new dams proposed by 1985 because the average cost of construction of new dams or projects of that nature are higher than the avoided costs. Well, that has just turned out to be not the case at all.

We see, particularly in Western States, the States of California, Washington, Oregon, and Idaho, hundreds and hundreds of applications that do propose new dams and diversions, and these are not the kinds—these are not high dams. These are mostly 15, 20, 30 feet in height, to divert mountain streams into pressure-capable concrete pipelines 1 or 2 miles in length, and utilizing the stream gradient to produce the hydroelectric energy.

These proposals are by in large PURPA-generated proposals. We include in our written testimony a little bit of analysis that we have been able to pull together that found, just of the last 2 years of proposals before FERC, that about 80 percent of the proposals have been by nonutilities, 98 percent have been under 80 megawatts, and about 40 percent nationally have been for this new dam-type design. Although I think in some of the Western States those figures are even higher, considerably higher.

At this time, there are 250 active proposals before FERC in the State of Washington. There are at least that many in California; in Idaho, there are about 105 active projects being proposed, and I will acknowledge that not a great number of projects have yet made it through the regulatory pipeline, but it is concerns over the numbers of projects that are before that pipeline that are leading resource agencies in a number of the States into very serious concern.

I guess I will just say that with regard to the need for some of these projects and the process by which they are handled by the Commission, there are major public investments that have been made by the ratepayers and by the Federal Government, State governments that are potentially at stake, according to resource agencies.

In particular, we look at the anadromous fish resources in the Pacific Northwest. In a recent letter to the Commission by the Department of Commerce, the Commerce Department pointed out that the Federal Government had spent some $684 million, along with public and private utilities, to try to restore anadromous fish runs; that large numbers of hydroelectric proposals endangered a number of the anticipated rehabilitation of these runs and caused considerable concern to the agency; that the Commission was not giving adequate attention to those kinds of concerns.

There are also an anticipated $800 million more to be spent in that area. So, I guess we are just cautioning the—or apprising the Congress of the special circumstances there and hope that, as we move forward, those can be dealt with and protect those investments.

I will just say that the issues, with regard to PURPA, have been addressed to some degree in the relicensing bills and the Senate and the House have both recognized the need to continue with existing and new dam distinction in how PURPA projects are being handled.

The House bill proposes a moratorium on new dam acceptances while impacts are being studied. Both bills include mandatory safeguards for projects associated with new dams. The Senate includes mandatory terms and conditions from fish and wildlife—mandatory conditions from the State and Federal fish and wildlife agencies, to protect these resources in the manner that the exemption programs are being handled currently at FERC.

The House goes beyond that to add limitations that these qualification facilities, located on rivers protected by States, ought to be disallowed if the States so object.

We think it is inappropriate to promote small hydro development on lands that States have protected under statute.

With regard to how the transition is to take place, we would just reiterate our opposition to the grandfather that was included in the Senate bill, that would grandfather as many as 2,000 new hydroelectric proposals that have come in over the last several years, including those projects that have been proposed at a preliminary permit stage at this point.

Finally, we would just suggest that the committee take into account the problems posed by the reconstruction of new dams that we consider—we think that that may be an issue that the Conference will need to address on the relicensing bill and that those projects, wholly reconstructed projects, particularly when the dams have been washed out years or decades ago, ought to be treated in the same manner as PURPA projects at new dams.

Thank you, Mr. Chairman.

[The prepared statement of Mr. Conrad follows:]

STATEMENT

OF

DAVID R. CONRAD

REPRESENTING THE

FRIENDS OF THE EARTH
IZAAK WALTON LEAGUE OF AMERICA
NATIONAL AUDUBON SOCIETY
TROUT UNLIMITED

BEFORE THE SENATE COMMITTEE

ON

ENERGY AND NATURAL RESOURCES

REGARDING

HYDROELECTRIC POWER AND
THE IMPLEMENTATION OF THE
PUBLIC UTILITY REGULATORY POLICIES ACT

JUNE 5, 1986

Mr. Chairman and members of the Senate Energy and Natural Resources Committee my name is David R. Conrad. I serve as Washington Representative and as Water Resources Specialist for Friends of the Earth. I appreciate the opportunity to appear before the Committee to discuss the implementation of the 1978 Public Utility Regulatory Policies Act (PURPA). I will focus my comments principally on the serious environmental problems that have arisen because of PURPA's promotion of hydroelectric power projects through its special marketing incentives, and the Federal Energy Regulatory Commission's (FERC) handling of approvals of these projects.

Mr. Chairman, I will begin by saying that PURPA's hydroelectric program may well constitute the most significant new and identifiable threat to the nation's finite and dwindling heritage of free-flowing rivers and streams. The PURPA incentives, coupled with FERC's licensing practices have resulted in and have significant potential for damage to stocks of commercial and sport fisheries, loss of recreational river resources and white water-boating streams, impacts on aesthetic resources and impacts on a wide variety of traditional uses of rivers and water. Unless changes are made in PURPA and the manner in which FERC licenses projects, environmental losses will continue and worsen.

PURPA-induced construction of new dams and water diversion projects is causing and will continue to cause the greatest adverse impacts. This was never intended by the Congress when

PURPA was established. Unprecedented numbers of new hydro dam proposals have flooded FERC's dockets since PURPA's implementation rules went into effect in 1980. The bulk of these applications have come from non-utilities that upon application will likely qualify for PURPA's avoided-cost pricing, mandatory interconnection and regulatory relief benefits under the Commission's rules. While the majority of applications have been for preliminary permits which generally represent minimal investment in a project, unprecedented and growing numbers are for license or exemption construction authorizations which threaten free-flowing river resources.

The problems stem in large part from an inappropriate and over-zealous promotional attitude of the Federal Energy Regulatory Commission towards hydroelectric development, an attitude which too often seriously clouds its judgement in implementing its public interest responsibility to protect the environment. The problems are exacerbated by institutional relationships between FERC and other units of government. Agencies with natural resource planning and management responsibilities, in particular, are too often relegated to a comments-only status. This has been the case for state agencies in hydroelectric licensing since the Supreme Court's First Iowa decision in 1946. It was also the case for most federal land management agencies until the 1984 Supreme Court Escondido decision regarding federal reservations.

Conservation organizations have from the beginning supported a vigorous PURPA program to encourage cogeneration and environmentally-sound small power production. However, FERC's handling of its approval process for hydroelectric projects and in particular its administrative expansion of PURPA's applicability to new dams in 1980, has led us to conclude that PURPA's application to new hydropower development must be severely curbed. Without additional controls on the siting, environmental conditioning and constraints on promotional incentives for hydroelectric development, there may well be a significant erosion of support for this program due to the growing realization that the environmental costs are outweighing the other public benefits being derived.

I. THE RECORD SHOWS THAT CONGRESS DID NOT INTEND PURPA BENEFITS TO APPLY TO NEW DAMS WHEN THE LAW WAS PASSED

Mr. Chairman, the magnitude of environmental problems with PURPA promoted technologies would be far less if the Commission had followed Congress' directives with regard to hydroelectric power and limited the applicability of PURPA Section 210 benefits to hydroelectric power projects associated with already existing dams. The legislative history of PURPA shows that in choosing to foster small power production, Congress specified technologies which were expected to be relatively benign environmentally: biomass, waste, solar, geothermal and renewable resources. The Conference Report stated specifically that in order to qualify for the extraordinary new incentives provided by PURPA, small hydropower facilities should be located at "existing dams."

Specifically, the Conference Report says:

> The definition of a small power production facility includes solar electric systems, wind electric systems, systems which produce electric energy from waste or biomass, and electric energy storage facilities. *The conferees intend that water be included within the meaning of the term renewable resources with respect to hydroelectric facilities at existing dams.* (Emphasis added).
> (H. Conf. Rept. No. 95-1750, 95th Congress, 2nd Session), reprinted 1978 U.S. Code Cong. and Ad. News,7797,7283.

The entire preceding two year legislative history of PURPA, to the extent it focused on hydroelectric power, focused on the retrofitting of existing dams and on water supply and irrigation conduits. Both the legislative language and debate were consistent in that regard. Senator Percy, who was primarily responsible for the Senate amendment that eventually became Section 201 of PURPA, summed up the thinking in his floor statement on the bill:

> We are somewhat more familiar with the case of small hydroelectric dams. The tireless efforts of David Lilienthal have inspired many to explore the potential of abandoned mill dams, aqueduct dams, and flood control dams. Within the next four years we could see hundreds of these dams *restored* to service. Now no one claims that small hydro sites will ultimately add more than a percent or two to our electricity supply. But for some medium-sized towns a small hydroelectric project could mean that they can attract a new industry or keep several hundred jobs at a declining mill. (Emphasis added).

In 1980, when FERC adopted its final rule regarding fuel use and eligibility for PURPA incentives, it dismissed Congress' explicit limitations on the PURPA incentive program, and went far beyond the retrofitting of existing dams. While FERC acknowledged the existing dams only limitation in both the staff paper and proposed rules leading up to the final rulemaking, it summarily abandoned the limitation with the following statement in the preamble to the final rule:

> Another issue raised by the proposed rule was the limitation of renewable resources to water used at existing dams. Commenters urged the Commission to expand the definition of renewable resources to include water used at new hydroelectric facilities. The Commission has viewed the Conference Report and has determined that the conferees did not intend to restrict the term renewable resources to water used only at existing dams. The Commission believes that such an interpretation conflicts with the conventional use of the term "renewable resources" as including all hydroelectric sources, not just those using existing dams. Therefore, the Commission intends that the term renewable resources applies to water used at existing and new hydroelectric facilities of less than 80 megawatts.
> (45 Fed. Reg. 17959, 17966 (March 20, 1980), codified at 18 CFR ss292, 204(6), 1984).

Further, the Commission so fundamentally misjudged the environmental significance of its decision that it declined to prepare an environmental impact statement. The decision not to do a full-scale environmental analysis was based, in part, upon a "market penetration" analysis, described in the environmental assessment (EA) that was issued shortly after the implementing rules were adopted. The EA predicted that of the approximately 3000 undeveloped hydroelectric sites in the U.S., "none" would likely be spurred to development by 1985, and only a "moderate" number would be spurred by 1995 (with "significant" environmental impacts , however), because the average construction costs for new and small scale hydroelectric dams "are significantly higher than avoided costs."

It has become abundantly clear that the Commission's economic predictions in the Environmental Assessment were seriously wrong. The Commission's dockets have since been flooded with hydroelectric development applications, mostly of the PURPA variety, a large portion of which involve new dams and diversions. FERC's gross misjudgement of the impacts of extending PURPA benefits to new dams has caused us to lose confidence in FERC's ability to carry out its public interest and environmental protection responsibilities under its existing authorities.

Three years ago, fourteen regional and national conservation organizations petitioned FERC to reopen the initial PURPA rulemaking and to prepare the needed environmental impact statement in light of the variance with Congress' directives and the flood of new hydropower applications. FERC refused to act on the petition for more than two and one-half years until it recently requested a remand from an appeal to the 9th Circuit Court of Appeals in order to affirmatively act on the petition in

January of this year. FERC declined to reopen the rulemaking and the case is once again on appeal.

II. THE COMMISSION HAS SORELY MISJUDGED THE NUMBERS OF NEW PROJECTS AND THEIR POTENTIAL FOR MAJOR ENVIRONMENTAL DAMAGES FOSTERED BY ITS PURPA RULES

The period of 1980-1985 saw filings for more than 5000 preliminary permits, and over 2000 hydroelectric license or exemption applications at FERC. While many of the earlier applications centered on the retrofitting of existing dams and water conveyances, increasingly the numbers are developments at previously undeveloped sites. By and large, developments at undeveloped sites and at totally breached former damsites involve the greatest potential for environmental harm.

So many new diversion-style "run-of-the-river" small hydroelectric projects have been proposed in California, for instance, drawing such major public protest, that in April of last year the State Water Resources Control Board recommended that the State Energy Commission separate its consideration of retrofit projects from new, diversion-style projects in analyzing the future of hydroelectric power in the state. At the time the Board had 275 water rights applications pending for small hydro projects. With regard to new, run-of-the-river small hydro projects, the Board found "significant environmental and public interest impacts" and "cumulative impacts" where multiple projects are concentrated in an area. The Board also found the following:

> Testimony presented at the water right hearings indicates that run-of-the-river projects are not being developed on the basis of the amount of energy that can be generated at least cost to the environment, but that capacity is being determined on the basis of the financial package that is put together to finance the project, that is, the amount of water that is required to generate enough energy to sustain a 20 percent internal rate of return to investors in addition to tax benefits. _We have found that project developers strenuously argue against leaving the necessary amounts of water in a stream to protect water-dependent resources and other beneficial uses._ (Memorandum of April 3, 1985, From the CA Water Resources Control Board to the California Energy Commission for Hearings on State Energy Plan.)

The Water Board also cited "damage to fishery resources, loss of riparian vegetation and consequent loss to wildlife habitat, degradation of recreational sites, loss of recreational opportunities, including white-water rafting, kayaking and canoeing, and aesthetic losses and damage to the recreationally-based economies of mountain counties and communities where jobs and dollars are dependent upon recreational resources" as the principal focus of public concern about the proposed hydro projects.

It also found that most proposed new small hydro facilities would operate only during spring runoff when other hydro facilities are at peak capacity, and that:

> The rate structure in the power purchase contracts between utilities and hydropower producers recognizes that there will be times when the utilities will be required to spill, foregoing use of their own generating facilities because they are forced to buy the power that is being produced by the small hydro qualifying facilities.

The California Water Board drew a strong contrast between "retrofit" projects (existing dams or conduits) which were often not protested and had a much higher reliability, versus new diversion projects which are almost always subject to protest and have much shorter seasons of operation.

Similar problems have been experienced by natural resource agencies in other states. The State of Washington is currently tracking the progress of some 250 active hydroelectric project proposals, many of which are situated on or near anadromous fishery runs. Most of these proposals involve new dams or diversions by PURPA-eligible non-utilities. Concern for loss of habitat and other impacts have led to calls by the Washington Department of Fisheries for cumulative impact studies in most of the state's river basins.

In the Skagit basin, one of Washington's largest salmon producing basins, proposals are currently pending at FERC for thirty-six new hydroelectric developments, including seventeen new license applications. The state's Nooksack basin has twenty-five active hydropower filings with a dozen pending license applications and four recently exempted projects nearing or under construction. Also, the state's Snohomish River basin, a major natural producer of coho, chinook, pink and chum salmon has active applications for twenty-one new dam and diversion projects, including nine pending license applications. Numerous other rivers in the state are facing multiple project applications, most of which are PURPA-inspired.

In Oregon, a case on the West Fork of the Hood River is a good example of the problems that PURPA's applicability to new dam and diversion projects is causing.

An out of state company has recently filed permit applications for three new diversion-style hydro projects immediately below an area that was designated in the Northwest Power Planning Council's Fish and Wildlife Plan as an off-site mitigation project for anadromous fishery habitat improvement. Off-site mitigation is needed to reverse the major decline in Columbia Basin fisheries brought on by main-stem dams. Bonneville Power Administration ratepayers have already spent $650,000 in habitat improvements on twenty-three miles of stream. The state is managing the area as a no-fishing sanctuary for propagation purposes, but the construction of new dams and diversions would negate many of the gains ratepayers have been paying for. It is doubtful whether this area would have become a target for hydroelectric development but for the Commission's PURPA rules. Also, in the state's Deschutes River basin, five new diversion license applications continue to generate substantial controversy due to the impacts developments would have on Deschutes County's recreational economic base.

In Idaho, the state is facing pending active FERC hydroelectric applications for 105 projects, including forty-seven license applications. That total equals the number of currently licensed or exempted projects in the state, and has led state and federal resource agencies to call for cumulative impact studies especially concerning fisheries on most rivers in the state. More than fifty Idaho PURPA hydroelectric filings have been docketed at FERC in the past six months alone, including thirteen new license and exemption applications. Major concern has been raised about multiple non-utility filings for developments on the Henry's Fork of the Snake River which supports a world-renowned trout fishery. All of these filings come at a time when huge surpluses of generating capacity are being experienced by the region's utilities.

In regard to Northwest fisheries, a major public investment has been made in the region. In a February 1986 letter to the Commission regarding information requested by FERC for the Cumulative Impact Assessment Procedure (CIAP) being conducted for the Salmon River in Idaho, the Commerce Department's National Marine Fisheries Service cited expenditures to date of $684.7 million by federal agencies and public and private power companies, and planned federal expenditures of an additional more than $800 million, to enhance and restore northwest anadromous fisheries and their habitats.

Concern for the loss of habitat represented by the large numbers of new hydropower proposals in the region led the Service to make the following comments to the Commission:

> Continued development without the benefits of a regionally approved comprehensive development plan poses an especially significant potential for conflict. Continued degradation of habitat,

> blockage of mitigation routes, and inundation of spawning areas by new hydro development threatens to negate many of the ....enhancement,mitigation and restorative investments.

III. NON-UTILITY PROJECTS CONSTITUTE THE MAJORITY OF NEW HYDROELECTRIC FILINGS

For the past two years environmental organizations have had difficulty obtaining from the Commission accurate breakdowns of FERC applications that constitute new PURPA-induced dams and diversions at previously undeveloped sites. To shed some additional light, Friends of the Earth, the National Audubon Society and the National Wildlife Federation reviewed the Federal Register notices of license, exemption, and preliminary permit applications accepted by the Commission from January 1, 1984 to May 15, 1985. The results are attached.

Of a total of 1912 project application notices reviewed, 1145 were for projects described as in connection with existing dams and 724 involve construction of new dams or diversions. Thus approximately 40% of applications, nationally, in recent years, have been for undeveloped dam or diversion sites, by our best estimate. In some western states, in particular, those percentages are much higher although we have not been able to complete such a state-by-state breakdown.

Most important, it is clear that the vast majority of initial filings during this period have been made by non-utilities that are likely to be eligible for PURPA benefits under the Commission's rules. More than 80% of the filings were by non-utilities. Almost all (98%) of the filings were for projects less than than PURPA's 80 MW ceiling.

IV. LEGISLATION IS REQUIRED TO TARGET PURPA HYDROELECTRIC INCENTIVES TOWARD ENVIRONMENTALLY BENIGN PROJECTS AND TO IMPROVE THE PROTECTION OF FISHERIES, WILDLIFE, RECREATION AND OTHER NON-POWER VALUES IN FERC LICENSING.

Mr. Chairman, a basic failing of the Commission's PURPA program is that it fails to distinguish between hydroelectric power projects that represent relatively minor environmental impacts and those with profound individual or collective impacts on the environment. As Congress recognized in 1978, but as the Commission has refused to acknowledge, a clear dividing point should be established between projects proposed at existing dams and those projects proposed for undeveloped sites. There is no question that, in general, the impacts associated with wholly new developments are much greater and of a different nature than developments at existing dams.

Both the House and Senate have recognized the need for this distinction in the two relicensing bills, S.426 and H.R.44, that await House-Senate Conference. It is our firm position that PURPA's extraordinary incentives should not be extended to new dams and diversions in light of the major disruptions in water resource management, and the potential for major environmental impacts caused by the PURPA incentives.

The House legislation proposes a moratorium on FERC acceptance of new PURPA-eligible small hydro dam or diversion applications while a study of the impacts of such development is conducted. Such a moratorium and study would allow FERC and state and federal resource agencies the opportunity to further evaluate the risks posed by new hydro development.

Both the House and Senate legislation have recognized the need for additional safeguards to add assurances that certain PURPA new dam developments will not be environmentally harmful. For those new dam or diversion projects which are allowed to receive PURPA's special benefits, these added protections are essential.

The Senate bill requires new dam or diversion projects under PURPA to include the mandatory terms and conditions set by state and federal fish and wildlife agencies in licenses issued by FERC to protect those resources. This is accomplished in the same manner as exemptions are currently handled in Section 30(C) of the Federal Power Act.

The House bill includes a similar mandatory fish and wildlife term and condition requirement and adds that no new dam or diversion may receive qualifying status if it is located on a river designated for protetion by state law. We applaud both the House and Senate for taking steps along these lines. We strongly recommend that the Conference Committee adopt the House language, because in addition to supporting its stronger language for protection of fish and wildlife, we believe it is inappropriate for the federal government to encourage and promote hydroelectric power development on lands which a state has by law set aside for preservation or protection as natural areas. We are aware of several instances where PURPA hydroelectric projects are being proposed for state parks and state protected scenic rivers over objections of the states. Because of FERC's policies of not granting deference to states, because of court decisions giving FERC supremacy in licensing over state law, and becuse of FERC's declared policy of assuming all PURPA hydroelectric power is "needed" (see Olympus Energy), the states are placed at a major disadvantage in protecting their resources. Requiring small hydropower developers to conform to state and federal resource agency requirements in order to proceed is the minimum acceptable standard to assure that critical public resources are not abused by PURPA beneficiaries.

Another issue raised during debate on the relicensing legislation was that of a grandfather clause or transition rule to protect PURPA hydropower developers who have made substantial investments from the need to conform with the new environmental requirements.

Environmentalists strongly object to the transition rule adopted in the Senate bill which would grandfather as many as 2000 new PURPA dam or diversion preliminary permit or license filings made before April 11, 1986. Such a sweeping grandfather would negate the benefits of providing the new protections and place in jeopardy thousands of miles of free-flowing river habitat. A grandfather clause is not justifiable considering the resources that are at stake. We urge that members of the Senate Energy and Natural Resources Committee exercise extreme care in establishing any grandfather clause and note that as of April 31, 1986, some 528 license or exemption applications were pending at FERC. Many of these projects have been held up precisely over concern for the potential impacts on fisheries and other resources.

Finally, another issue needing to be addressed by conferees is the issue of reconstruction of breached dams. Instances exist where dams have been washed out and proposals are made for reconstruction, sometimes years or decades later, at or near the original site, while referring to the dam as "existing." When a dam and impoundment are not clearly "in existence," PURPA should treat the proposal as a new dam.

Mr. Chairman, the environmental problems associated with PURPA-induced developments are not limited to those at undeveloped sites by any means. Environmental organizations submitted extensive testimony last year during relicensing hearings about the need for improvements in FERC's handling of licensing. Some of our concerns were addressed in relicensing bills, some were not. Cited as major problems at FERC were: inadequate technical staffing and budget for an exponentially expanding workload, inadequate implementation of NEPA, overreaching authorities to promote hydropower development often at the expense of environmental protection, major failings in enforcement, inadequate deference to state and federal resource agencies and tribal governments, failure to require necessary environmental studies, and failure to prepare comprehensive plans for river basins.

The problems cited then still exist at the Commission. They in turn impact the quality of hydroelectric power decision-making and the agency's overall efficiency. It is our recommendation the relicensing conference make the substantive statutory improvements necessary to improve the Commission's handling of hydrolicensing and PURPA. The problems raised by the past five years' wave of PURPA hydro projects point to a continuing need for comprehensive river basin planning. The conflicts of unplanned developments will continue to increase in the future, not decrease. More congressional and legislative attention is needed in this area.

CONCLUSION

Mr. Chairman, all along we have maintained the position that PURPA's hydroelectric power incentives should only be applied to projects at existing dams. While this hearing has focused on PURPA's implementation, the problems of FERC's licensing program cannot be divorced from the effects of PURPA. The relicensing bills include other important measures to improve FERC's handling of hydropower. We want to particularly emphasize our support for the House bill's environmental language, which provides much needed strengthening of resource agencies roles in FERC's hydropower programs. We look forward to working with the Committee to resolve these issues in the near future.

Thank you for the opportunity to present our views. I would be happy to respond to any questions that the Committee may have.

INITIAL FILINGS ACCEPTED BY FERC FOR HYDRO PROJECTS, 1984 TO MID-1986 (MAY 15)

TOTAL NUMBER OF INITIAL FILINGS ACCEPTED: 1912[1] (noticed in Fed. Reg.)

UTILITIES FILING: 321
NON-UTILITIES FILING: 1582
UTILITY STATUS UNKNOWN: 9

FILINGS INVOLVING EXISTING DAM FACILITIES: 1149

Of those-
  Licenses: 270[2]
  Preliminary Permits: 678
  Exemptions: 197

FILINGS INVOLVING PROPOSED DAM FACILITIES: 724

Of those-
  Licenses: 174
  Preliminary Permits: 471
  Exemptions: 79

TOTAL FILINGS FOR- LICENSES: 472
  PRELIMINARY PERMITS: 1147
  EXEMPTIONS: 279

PROJECTS INVOLVING UNDER 80 MEGAWATTS CAPACITY: 1877
  OVER 80 MEGAWATTS CAPACITY: 35

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[1] This includes filings for preliminary permits, licenses, transfers and amendments to licenses, and exemptions (including conduit exemptions).

[2] License transfers and amendments are not tallied here, which accounts for minor numerical discrepancies.

FILINGS ACCEPTED BY FERC FOR HYDRO PROJECTS,**
1984 TO MID-1986 (MAY 15)

STATE	LICENSES	PRELIMINARY PERMITS	EXEMPTIONS	TOTAL
Alabama	2	19	2	23
Alaska	4	4	1	9
Arizona	1	7	-	8
California	77	202	63	342
Colorado	29	82	11	122
Connecticut	9	31	1	41
District of Columbia	-	1	-	1
Florida	-	7	1	8
Georgia	3	3	2	8
Hawaii	-	1	-	1
Idaho	39	94	19	152
Illinois	6	14	1	21
Indiana	5	28	1	34
Iowa	5	32	1	38
Kansas	-	7	2	9
Kentucky	5	25	-	30
Louisiana	5	5	-	10
Maine	19	27	16	62
Maryland	-	3	1	4
Massachusetts	13	53	5	71
Michigan	-	8	6	14
Minnesota	3	1	1	5
Missouri	1	1	-	2
Mississippi	2	5	-	7
Montana	18	27	11	56
Nevada	2	10	4	16
New Hampshire	30	47	19	96
Nebraska	-	2	3	5
New Jersey	7	7	1	15
New Mexico	5	8	1	14
New York	46	98	26	170
North Carolina	8	13	9	30

**included are initial filings, noticed in Federal Register

Filings Accepted by FERC for Hydro Projects,
1984 to Mid-1986 (May 15)

STATE	LICENSES	PRELIMINARY PERMITS	EXEMPTIONS	TOTAL
Ohio	4	7	1	12
Oklahoma	2	8	1	11
Oregon	12	30	7	49
Pennsylvania	20	30	7	57
Rhode Island	-	2	-	2
South Carolina	4	5	1	10
South Dakota	-	1	-	1
Tennessee	-	9	2	11
Texas	1	2	1	4
Utah	11	33	4	48
Vermont	17	21	9	47
Virginia	10	12	8	30
Washington	34	62	13	109
West Virginia	9	10	-	19
Wisconsin	7	11	1	19
Wyoming	3	16	-	19
TOTALS	486	1,147	279	1,912

The CHAIRMAN. Thank you.

Mr. Botkin, looking at your statement, as I view it, you, in effect, said that the basin impact or cluster impact is really addressed by the cross-analysis that accompanies each application; that each application must, in itself, review the effect that is added to the effects by other projects. Am I correct in reading your statement in that fashion?

Mr. BOTKIN. That is generally correct, Mr. Chairman. The difference between additive and cumulative effects is what is being addressed there. We felt that the case-by-case basis upon which FERC has historically judged our projects is a very effective way, but that the addition of the new FERC CIAP process could serve as a very good collective in greater overview process.

The CHAIRMAN. Would you expect on an application you might file today, that FERC would look at the effects of that project in conjunction with the effects of other known projects?

Mr. BOTKIN. Well, that would have to be a license application, of course, Mr. Chairman, and that would have to be added in at another phase of an existing CIAP. It could not be included, it is my understanding, in an ongoing CIAP. It is, more or less, you are cut off at the point to begin any given basin.

My projects are located in the Snohomish River Basin, which was the first basin in the country to be subjected to the process. We, in fact, were instrumental in working with the local and State agencies, as well as the Federal agencies, in devising our own sub-basin cumulative impact study.

We, in fact, completed a study which was to the complete satisfaction of all the agencies and tribes, and as a result we were exempted from the Snohomish River Basin CIAP.

The CHAIRMAN. In the absence of a cluster impact, a basin impact, would the effects of an individual project be judged in conjunction with the effects of others?

Mr. BOTKIN. I think, as a practical matter, all of the agencies and tribes now are very focused on the study of the cumulative or interactive effects that projects have on one another. So, under any process at any level, I think that they will be judged collectively.

The CHAIRMAN. Even if there were not a cluster impact analysis?

Mr. BOTKIN. Well, I think that is a formal term that has been devised in response to the insistence from, I think, primarily our end of the country, to treat these in a basinwide fashion, in a comprehensive fashion. But, again, as a practical matter, our Northwest agencies have developed a very formidable expertise in treating clustered projects, with or without the formal term.

The CHAIRMAN. Mr. Elston, there are a couple of things in your statement that strike me. One is that you say there should be a means by which the agencies should develop a sophistication to grade the nature of environmental intervention from those that you regard as responsible groups and those that you consider irresponsible.

Is there an objective test by which you can judge that?

Mr. ELSTON. Well, I didn't mean to imply that the group should be labeled responsible or irresponsible. I think that the record that I am talking about is a situation where you had a group of kyakers who wanted to use the river for, I would say, roughly 10 to 20 days a year, and we had negotiated with them essentially an agreement whereby they could do that.

We agreed to shut down our plants when they wanted to use it. The deal was closed. They had exactly what they wanted. They turned around and went to FERC and tried to tie us together with a project that was down river, essentially using us as leverage against that project to force that project—not us, it had nothing to do with us—agree to the same thing.

They filed, before FERC, what was an absolutely frivolous filing, and FERC, as a result of that, delayed the issuance of our license some 3 months on what I considered, and I think fairly so, no grounds whatsoever except that there was a piece of paper on the record that had a negative implication.

The CHAIRMAN. Let me refer you to the language that I am looking at on page 11 of your statement.

> The only thing wrong with this, that there is no discrimination by FERC between responsible comments from environmental groups and those from special interest splinter groups. In some cases, these splinter groups may even go against the interests of the larger environmental community.

That is a way of saying that there is a diversity of opinion.

I just wonder if you can tell me if there is an objective way we can define what a responsible comment from an environmental group is and what is a special interest splinter group that is, apparently by definition, irresponsible.

Mr. ELSTON. Mind you, I was characterizing the comments as responsible or irresponsible; not the groups as responsible or irresponsible, and I think that the record that I just described to you is the place to go to find the details. I think that any reasonable reading of that record would describe the actions of this particular group as irresponsible relative to the deal that they made with us when we gave them what they wanted on our development."

The CHAIRMAN. On page 12 you say, "However, FERC and the States should learn to differentiate between responsible comments and small, special interest comments."

Mr. ELSTON. Once again, I think we are referring to comments, not to groups, and I think that these particular comments, as I said, had been aired, had been considered, and at this stage of the process, I think should properly be characterized as irresponsible and should not have been considered. They had been fully aired.

The CHAIRMAN. Mr. Elston, at another point in your comments, you talk about growth rate projections. You have echoed something that has been said by a witness in an earlier panel, that projections in the past were wrong and the projections at the present time are probably wrong, too.

I agree with that statement, but I grope for an answer. What do we do? Do we drink lots of tea and read the tea leaves? Do we buy a ouija board? What is the alternative?

Mr. ELSTON. I think that was described in the Northwest was not a planning process; it was an addition exercise, and I see that in the Northeast, as well. I think that there needs to be more sophisticated planning on a regional basis in defining our capacity requirements in the future, No. 1.

No. 2, whenever you are trying to project into the future a growth rate and peak demand, you have to look at ranges, and I don't think it is terribly mysterious to know that when 5 years ago, or 6 or 7 years ago, the planners, so-called, were talking about 7 percent growth rates and are now talking about 1.5 percent growth rates, and we have just experienced 4.9 percent growth rate; that there just should not be those wide swings.

You cannot conduct your business in an orderly way.

The CHAIRMAN. There should not be, but there have been.

Mr. ELSTON. I think that it is just an over reaction, because of the political heat that people experience.

The CHAIRMAN. You think these professional engineers, economists, specialists are responding to public pressures in order to tailor the outcome to a preconceived notion?

Mr. ELSTON. I think that first of all it is not engineers that do it. It is basically bureaucrats, whether they are in the utilities, or the State agencies.

The CHAIRMAN. What is a bureaucrat?

Mr. ELSTON. Everyone in those agencies are bureaucrats because those are large bureaucracies.

The CHAIRMAN. You were a bureaucrat yourself, once.

Mr. ELSTON. Indeed, and I don't mean the word pejoratively at all.

The CHAIRMAN. And at that time, your opinion didn't count for much because you were a bureaucrat, and now that you are not one, we should listen to you.

Mr. ELSTON. I am not suggesting that I have the wisdom at all. I am suggesting that there is some evidence before us, in terms of these wide swings in numbers that says that there is a problem. I also firmly believe that 1.5 percent growth rate, as a base——The question is, What risk do you want the consumer to take, the ratepayer to take? I think that there is a well-established body of economic analysis that shows that it is a mistake to underestimate your capacity requirements; that the consumer ends up paying more in the long run if in fact you do that; and that that is what is happening today.

I think it is going to swing around several years from now, but I think that public officials that have been before and seen these wide swings, should be stepping out today to recognize that that is what is going on.

The CHAIRMAN. So you infer error just from the fact of the wide swing?

Mr. ELSTON. Yes, I do. I infer that any wide swings like that, when you are talking about 20, 30, or 40 year projections, don't make any sense. I think they simply do not make sense from a public policy point of view.

The CHAIRMAN. There are those who argue that the consequences of overcapacity are more grave than the consequences of undercapacity. How do you respond to that?

Mr. ELSTON. I would be happy to respond in more detail, and once again, I don't represent myself as an expert on this, but I have read utility systems' experts that make the counter argument, and I thought that they were rather persuasive, and I guess the real point is this: The types of developments that are being put in place under PURPA in our part of the country, and I think throughout the country, are basically smaller projects.

They don't require you to, in fact, project 20 years ahead in order to justify your plant. You are looking at 3, 4, 5, 6-year lead times in these small, modular developments. I can tell you that in New York State, the Governor has embraced the concept specifically of building modularly, to build smaller plants in the future, not the large plants, and wherever possible, to purchase that power from independent producers.

It just gives you more flexibility and you are not relying—I am sure I would make the same mistakes, all right, were I in those positions. But the question is, how do you get out from under that problem? I think that we have before us, in PURPA, a mechanism for doing that, by bringing on these smaller plants 1 year at a time, not looking at a 15-year development process.

The CHAIRMAN. I am one who comes from an area where we were threatened with the shortages. We have at various times in the past seen rolling brownouts, and I guess maybe if the elevator in the Trade Center does not work on a given day, it does not matter unless you happen to be in the Trade Center on that day.

If you are, then it becomes a rather critical concern. I guess maybe, because of my own experience, I come down on the side that managing surpluses is less troublesome, less costly than managing shortages.

But not everyone agrees with that point of view, and that is the reason I asked the question, because there are some responsible people who will argue that the ratepayers, indeed, are saddled with excessive costs for long periods of time and that we ought not to be forcing current consumers to pay for future needs. They ought to be required to pay for their own needs.

I find a little fault in that because they are enjoying the benefits of somebody else's investment and payment in the past. But, I think it is a serious question and we, as policymakers, have to try to balance the two positions because they are quite different positions.

Mr. Conrad, on page 10 of your statement, you are talking about the money that has been spent in offsite mitigation for anadromous fishery habitat improvement, and that happens to be something that is near and dear to my heart, having spent a lot of the time and effort to make certain we had adequate funds to do that.

Mr. CONRAD. Yes, sir.

The CHAIRMAN. Because I believe that the mitigation and the restoration of the anadromous fishery is a matter of national importance, and I know certainly it is of regional concern.

But you imply, I think, that the construction of new dams would not consider the mitigation efforts. Would not the FERC processes require the consideration of both the need for mitigation and the extent of mitigation efforts underway?

Mr. CONRAD. Yes, sir. Certainly, it would bring those considerations into play, and I did not mean to imply that it simply would not be. In fact, one of the implications of that vignette, the Oregon situation, is that a large amount of time is being spent by resource agencies, now, reviewing projects, having to document the case for why these particular developers should not be allowed to construct on those streams, even though that particular stream is obvious a serious—it would represent a serious mistake if—or at least, diversion from the effort to effectuate the off-stream mitigation.

The **Chairman**. But is it necessarily true that the construction of a project is necessarily in opposition to the mitigation efforts?

Mr. **Conrad**. I think, no. In this particular case, it is my understanding that it definitely would be.

The **Chairman**. It may or may not be; I do not know the facts in that case. But do they not ordinarily require now some mitigation in connection with the construction of a new project?

Mr. **Conrad**. There can be, if the commission decides that that is what is necessary. On exempted projects, the mitigation is set by the fish and wildlife agencies, and we have considerable confidence that that is being done and can be done well.

In the case of licensed projects, that decisions is the commission's, and I think the argument that we would make is that, for these special PURPA incentives, that certainly an argument can be made that the locus of decisionmaking should be shifted to the agencies responsible for those resources. As a matter of fact, that is a concept that thus far has been worked into the relicensing bill in the Senate.

The **Chairman**. Does that simply reflect a greater confidence in the fish and wildlife agencies than in the other agencies?

Mr. **Conrad**. Than in FERC, yes, sir.

Mr. **Elston**. If I could comment, Mr. Chairman. There are two things to be said: One is that it is my experience that FERC has never, in my experience, acted in contravention to any State's requirement from the fish and wildlife people. There is often disagreement at the State level, but I just have not seen a situation in our area where FERC has gone in contravention of the interests as articulated by the State.

Second, and at least this is true in our State; I cannot talk about the rest of the Nation, but the fish and wildlife people in the Department of Environmental Conservation welcome our proposed development, because at a minimum what they do is simply require us to do a whole range of studies on the quality of the fisheries and mitigation and, it is a vehicle for them to gather information on the river. We have to pay for it. They like it because they don't have to go to get a budget to do these studies, and don't have the budget to do it. They end up with an enhanced body of information on these rivers.

I think the discussion with some of those individuals would confirm that they rely on this, in fact, for a good deal of their planning.

The **Chairman**. Mr. Conrad, I want to ask a question. I am going to make a comment and I do not want to prejudice or indicate any prejudice about your statement by the comment that I make. I am trying to understand what your statement means.

You have indicated you would like to have a generalized policy; that PURPA projects can be at existing dams but no new dams. Is that a correct statement?

Mr. **Conrad**. That is certainly our sense of what the current law ought to be, or is, and that——

The **Chairman**. That is what you contend for as policy, either under existing law or by way of a change in the law if necessary.

Mr. CONRAD. Yes, sir.

The CHAIRMAN. I would assume that if we really get down to cases and examine cases, you would say that indeed there may be some cases in which a project at an existing dam could do more damage than hypothetically might be done at some new dam?

Mr. CONRAD. Yes, sir.

The CHAIRMAN. So the statement that you make in favor of projects confined to existing dams and in opposition to the new dams would be a more generalized response on your part that it is more likely to cause less damage if you do it that way than to do it in the alternative way.

Mr. CONRAD. Yes, sir; and I think that is the logic that we saw that the Congress used in 1978 in initially putting the PURPA Program together.

The CHAIRMAN. But you still believe that is correct.

Mr. CONRAD. Yes; and we believe, as we have stated on the record in the relicensing hearings, that considerable additional attention needs to be paid to fish and wildlife resources and environmental handling by the commission of licensed projects, generally speaking.

The CHAIRMAN. I will pass for the moment any debate as to whether or not that is what there is in the PURPA statute. I am just trying to get to what your opinion is and what it is based on.

Mr. CONRAD. Yes, sir.

The CHAIRMAN. Thank you, very much, and I thank all three of you for your testimony here today.

The panel on the policy issues. Gentlemen, you are welcome before the committee. Your entire prepared statements will, of course, be placed in the record in full. I would invite you to summarize or highpoint those statements, or deliver the statement as you see fit at this point.

We will start with Dr. John Anderson.

STATEMENT OF DR. JOHN ANDERSON, EXECUTIVE DIRECTOR, ELECTRICITY CONSUMERS RESOURCE COUNCIL

Mr. ANDERSON. Thank you, Mr. Chairman. I appreciate the opportunity to be here. I am John Anderson, executive director of the Electricity Consumers Resource Council.

We are a group of extremely large industrial cogenerators, as well as electricity consumers. We produce products in nearly every State ranging from steel, aluminum, chemicals, industrial gasses, glass, motor vehicles, and a variety of other products.

Our members represent approximately 10 percent of all industrial electricity consumption and nearly 5 percent of the total electricity consumption in the United States.

However, we are here today to express views on cogeneration. Our members also are extremely large cogenerators, but the point that I would like to emphasize to begin with is that they are much larger consumers of electricity. And, thus, as consumers of electricity, we think we present your committee a unique view.

We are very interested in seeing that barriers to cogeneration are eliminated. However, we also are very interested in seeing that ratepayers are protected. At the outset, I would like to emphasize my comments are limited to cogeneration, and particularly large cogeneration projects because our members' involvement in the others are limited.

Prior to 1978, cogenerators found that utilities were able to use their monopolistic powers to stiffle many efficient cogeneration projects. PURPA, as we know, was passed in 1978, and in our view, it has worked quite well. However, despite its resounding success, utilities propose changes in PURPA because of certain alleged problems.

In our view, these problems are largely myths, and I would like to take a few moments to discuss some of them. Myth No. 1, for example: Cogeneration causes reliability problems. In fact, we believe the opposite is generally true for several different reasons, such as, our member companies operate QF's at capacity factors that are higher than most utility generators.

Second, most QF's are smaller than most utility generators. Thus, the statistical probability that all of the cogenerators will have forced outages declines as the number of cogeneration facilities increases.

Third, QF's sometimes agree to supply backup power to utilities in emergencies. I refer to several specific examples in the body of my text, but I would like to mention a couple of them.

During the last emergency in Texas, last year, nonfirm cogenerators in the HL&P service area, contributed 222 megawatts of power, despite the lack of any contractual commitment to do so. This was in addition to the over 750 megawatts being provided at the time in firm contract agreements.

Bethlehem Steel Corp. and Baltimore Gas & Electric have had a contract in place for more than 20 years that requires Bethlehem to run its more than 100 megawatts of cogeneration capacity at Sparrows Point in Baltimore on oil or natural gas and provide the energy to BG&E if blast furnace gas is not available during emergencies.

This has usually happened several times a year and Bethlehem is always able to comply.

Myth No. 2: PURPA requires utilities to pay cogenerators rates that exceed or equal avoided costs. This simply is not true. In fact, rates above avoided costs violate PURPA. Usually the situation, in our view, is self-correcting. Commissions eventually reduce above-avoided cost rates. Recent actions by the California and the Idaho Commissions highlight this point.

Additionally, most large QF's must negotiate rates below avoided costs to be able to complete contract negotiations, which is a requirement for the project financing.

A third myth: PURPA increases costs for other customers. By definition, properly implemented, PURPA rates cannot increase costs for other customers. Rates for the purpose of cogenerated power that increase costs to other customers are in violation of PURPA and should be changed.

Myth No. 4: PURPA rates artificially stimulate cogeneration investments. Elcon member companies base their decisions to build QF's on estimates of displaced power costs, not on PURPA rates. Ironically, this market-oriented decision to build cogeneration projects often drives industrials to add new capacity in precisely those areas where excess utility capacity now exists.

This is true because the addition of large, very expensive central station utility generation units often causes dramatic rate shocks and increases reserve margins to very high levels.

Myth No. 5: Cogeneration encouraged by PURPA displaces more efficient utility generation. We must distinguish between engineering and economic efficiency. Engineering efficiency is measured by heat rates. The number of BTU's that are required to produce a kilowatthour of electricity.

But consumers look at economic efficiency. Large, new utility units are economically inefficient. Their high costs drive industrials to cogenerate. In such instances, cogeneration is thus displacing inefficient, from an economic standpoint, utility generation.

Myth No. 6: PURPA requires a utility to buy cogenerated power whether it needs it or not. That is untrue. Utilities always need energy. They may or may not need power. No consumer is harmed in any way, as long as energy payments do not exceed avoided energy costs.

PURPA does not allow capacity payment unless capacity costs are avoided. Utilities do not have to power; only the energy.

Myth No. 7: PURPA prohibits utility ownership of cogeneration. In my view, this is the ultimate fallacy. PURPA places no limit on utility ownership of cogeneration facilities. In fact, utilities have an obligation to invest in cogeneration if it is the lowest cost way to meet their customers' needs.

If the ownership limitations were lifted on qualified facilities, many utilities would not deal fairly with nonutility owned QF's relative to their wholly owned QF.

Myth No. 8: Economic efficiency and consumer equity require competitive bidding. Assertions that competitive bidding should be applied to purchases of cogeneration fail to understand the complexities of the market.

Competitive bidding won't work when there isn't any competition, and by this I mean, when there is only one buyer.

Implementation of competitive bidding, if it is to occur at all, must be accomplished with access to other potential buyers by requiring utilities to wheel cogenerated power to distant locations.

Although PURPA helped level the playing field, cogenerators do face several problems.

I will highlight two. First, backup maintenance and standby rates. Although PURPA addressed these, monopoly utilities still are able to exercise substantial power over QF's by refusing to bargain in good faith regarding backup maintenance and standby power. This is an area we think FERC should spend some time looking at.

Second, is the refusal to wheel. Industrial cogenerators often are high with a double whammy; they are underpaid when they sell QF power and overcharged at other locations when they buy power.

A logical solution would be to allow the industrials consumer power generated at one location at others of its own sites. This requires wheeling, but utilities refuse to wheel.

The issue of wheeling is very complex and it involves far more than PURPA or movements of cogenerated power. We strongly urge this committee to initiate proceedings on the general issues of wheeling, to increase competition and efficiencies and lower costs.

In closing, we offer this committee two recommendations: First, we strongly suggest that PURPA should not be changed for the reasons that I have stated before. And, second, we strongly urge this committee to explore wheeling. Many of the alleged PURPA problems can be alleviated through increased wheeling and access to the grid by cogenerators and industrial electricity consumers.

Congress should initiate proceedings on the general issue of wheeling. Care must be taken to appropriately consider all views. However, efforts to increase competition, which most certainly is enhanced through the increased wheeling and access to the grid is consistent with this administration's philosophy and our Nation's economic system.

It makes good business sense and should be explored.

Thank you, very much, for the opportunity.

[The prepared statement of Dr. Anderson follows:]

ELCON

STATEMENT OF THE
ELECTRICITY CONSUMERS RESOURCE COUNCIL (ELCON)
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
ON
PROPOSED CHANGES TO THE
PUBLIC UTILITY REGULATORY POLICIES ACT (PURPA)
JUNE 5, 1986

I am John Anderson, Executive Director of the Electricity Consumers Resource Council (ELCON). I am pleased to appear before this Committee today to present the industrial electricity consumer's views on proposed changes to the Public Utility Regulatory Policies Act of 1978 (PURPA) -- particularly as these changes affect cogenerators.

ELCON is a group of large industrial consumers of electricity with facilities in most of the 50 states and many foreign countries. Our members produce a wide range of products including steel, aluminum, chemicals, industrial gases, glass, motor vehicles, textiles and food. The attached Fact Sheet lists the ELCON member companies and our fundamental principles.

These firms consume approximately ten percent of all electricity sold to industrial customers and nearly five percent of all electricity consumed in the United States.

ELCON members require a very large and reliable supply of electricity at reasonable prices.

In meeting their needs, our members generate and cogenerate large quantities of electricity. They have done so for many years.

But our members are much larger purchasers of power than they are generators.

Thus, as very large net buyers of electricity, we offer this Committee a unique view. We are very interested in eliminating barriers to industrial cogeneration development. However, we desire the implementation of policies that assure the protection of ratepayers.

This testimony is organized as follows. First is a summary and our recommendations. We then present an overview of cogeneration -- what it is, why it is efficient, and how our members are involved. Next we describe PURPA and present our views of its successes. Fourth we discuss both alleged and real problems associated with PURPA.

I recognize that PURPA affects both cogenerators and small power producers. However, my comments are limited to cogenerators as the ELCON involvement with small power producers is limited.

I. SUMMARY AND RECOMMENDATIONS

A. Summary

Industrial firms often need thermal energy in their manufacturing processes. Cogeneration -- the sequential production of useful thermal energy and electrical or mechanical power -- is a very efficient way to produce both electricity and steam. By capturing energy otherwise wasted, cogeneration can convert more than 75 percent of the energy content of fuel to useful work; the efficiency of conventional generation is less than half this amount.

Prior to 1978, cogenerators found that utilities were able to use their monopolistic power to stifle many efficient cogeneration projects. Congress enacted the Public Utility Regulatory Policies Act of 1978 (PURPA) in part as an attempt to neutralize the utilities' monopolistic advantages.

PURPA has worked quite well. Indeed, between 1980 and 1985, the Federal Energy Regulatory Commission (FERC) has received nearly 2,000 requests for qualifying status from potential cogenerators representing nearly 30,000 MW of capacity.

Despite its resounding success, utilities propose changes in PURPA because of certain alleged "problems." These alleged problems largely are myths. Specifically:

o Myth #1 : Cogeneration causes reliability problems.

Response: In fact, the opposite generally is true for several reasons including:

* ELCON members QFs operate at capacity factors higher than utility generators.
* QFs are smaller than most utility generators. The statistical probability that all cogenerators have forced outages at once declines as the number of cogeneration facilities increases.
* QFs sometimes agree to supply backup power to utilities in emergencies. Several specific examples of this backup service are presented at page 19 below.

o Myth #2 : PURPA requires utilities to pay cogenerators rates that equal or exceed avoided costs.

Response: This simply is not true. In fact, rates above avoided costs violate PURPA. Usually the situation is self-correcting. Commissions eventually reduce above-avoided-cost rates. Recent actions by the California and Idaho commission highlight the point that problems are self-correcting and and do not require Federal intervention. Additionally, most large QFs must negotiate rates below avoided costs to be able to complete contract negotiation, a requirement for project financing.

o Myth #3 : PURPA gives the states unfettered authority to set rates for the purchase of QF power.

Response: PURPA establishes avoided costs as the ceiling for rates set by the states. Above-avoided cost rates are not only in violation of PURPA, but are also discriminatory. They thus violate PURPA as well as other federal and state statutes.

o Myth #4 : PURPA increases costs for other consumers.

Response By definition, properly implemented PURPA rates cannot increase costs for other customers. Rates for the purchase of cogenerated power that increase costs to other consumers are in violation of PURPA and should be changed.

o Myth #5 : PURPA rates artificially stimulate cogeneration investments.

Response: ELCON member companies base their decisions to build QFs on estimates of displaced power costs. They do not base their decisions on rates established under PURPA rules. Ironically, this market-oriented decision process often drives industrials to add new capacity in precisely those areas where excess utility capacity now exists. This is true because the addition of large, very expensive central station utility generation units often causes dramatic rate shocks and increases reserve margins to very high levels.

o Myth #6 : Cogeneration encouraged by PURPA displaces more efficient utility generation.

Response: From a consumer standpoint, the opposite often is the case. Large new utility generators usually are so expensive that they are not economically efficient. Engineering efficiency is irrelevant if industrials can produce power at lower costs.

o Myth #7 : PURPA requires a utility to buy cogenerated power whether it needs it or not.

Response: Utilities always need energy. No consumer is harmed in any way as long as energy payments do not exceed avoided energy costs. PURPA does not allow capacity payments unless capacity costs are avoided. Utilities do not have to buy power -- only energy.

o Myth #8 : PURPA prohibits utility ownership of cogeneration.

Response: This perhaps is the ultimate fallacy. PURPA places no limit on utility ownership of cogeneration facilities. In fact, utilities have an obligation to invest in cogeneration if it is the lowest cost way to meet their customers' needs. If the ownership limitation were lifted, many utilities would not deal fairly with non-utility owned QFs vis-a-vis their wholly-owned QFs.

o Myth #9 : The operating and efficiency standards specified by PURPA are flawed.

Response: PURPA specifies no operating or efficiency standards. If there are problems with the standards set by FERC in the rules implementing PURPA, they should be studied, debated and corrected. FERC can take these actions with a rulemaking. PURPA should not be amended to include operating and efficiency standards.

o Myth #10: Economic efficiency and consumer equity require competitive bidding for available capacity credits.

Response: Assertions that competitive bidding should be applied to purchases of cogenerated power fail to appreciate the complexities of both (1) the process by which cogeneration facilities are determined "economic" and (2) the power granted a utility with its "exclusive service territory." Competitive bidding would eliminate some of the most efficient cogeneration units -- those custom-engineered and designed. Additionally, "competitive" bidding won't work when there is no competition -- that is, when there is only one buyer. Implementation of competitive bidding, if it is to occur at all, must be accompanied with access to other potential buyers by requiring utilities to wheel cogenerated power to distant locations at the cogenerator's discretion.

Although PURPA helped "level the playing field," real problems remain. They include:

- Backup, maintenance and standby power rates.

  Utilities still are able to exercise their substantial monopoly power over QFs by refusing to bargain in good faith regarding backup, maintenance and standby power rates. FERC and state regulatory commissions have the authority to do more than they presently have done without a change in law. They should be encouraged to do so.

- Refusal to wheel

  Industrial cogenerators often are hit with a "double whammy." They are underpaid when they sell QF power and overcharged at another location when they buy power. A logical solution would allow the industrial to consume power generated at one location at other sites. This requires wheeling. Utilities refuse to wheel.

  The issue of wheeling is very complex. It involves far more than just PURPA or movements of cogenerated power. We strongly urge this Committee to initiate proceedings on the general issue of wheeling to increase competition, and efficiencies and lower costs.

- Ownership restrictions

  The Public Utility Holding Company Act of 1935 (PUHCA) and PURPA and the rules implementing the acts unduly restrict industrials from entering into joint ventures that would meet the steam and electricity needs of both investors. Although related to PURPA, this issue should be discussed in the broad context of deregulation of generation. We urge this Committee to initiate proceedings to consider relaxing these restrictions.

- Facility size restrictions

  PURPA restrictions on the size of certain types of all power production facilities eligible to receive qualifying status may negatively impact the development of desirable projects. However, changes must be considered carefully. This Committee is urged to initiate either oversight hearings on the issue or request a detailed study of the issues by FERC.

B. Recommendations

1. PURPA should not be changed

Avoided costs should continue to be the ceiling for rates paid for the purchase of cogenerated power. The ceiling should not be less than 100 percent of avoided costs. There should be no floor.

Utilities should be required to provide non-discriminatory rates for backup, maintenance and standby power. Utility ownership of qualified facilities should be limited to less than 50 percent.

2. Congress should explore wheeling

Many of the alleged PURPA "problems" can be alleviated through increased wheeling and access to the grid by cogenerators and industrial electricity consumers. Congress should initiate proceedings on the general issue of wheeling. Care must be taken to appropriately consider all views. However, efforts to increase competition, which most certainly is enhanced through increased wheeling and access to the grid, is consistent with this Administration's philosophy and our nation's economic system. It makes good business sense and should be explored.

II. BACKGROUND

A. What is Cogeneration?

Cogeneration is defined as the sequential production of electrical or mechanical power and useful thermal energy from the same fuel source.

Cogeneration utilizes fuel more efficiently than conventional generation by recovering energy that otherwise would be wasted. When used appropriately, cogeneration may recover from the fuel being used more than twice the amount of useful energy recovered by conventional utility generation.

B. Industrials Cogenerators

Industrial firms often require thermal energy (heat or steam) in their manufacturing processes. For example, plants that produce chlorine and caustic soda require low pressure (or process) steam to evaporate water from dilute caustic soda, making the caustic soda into a salable product. In refineries, process steam is used to distill crude oil, separating it into gasoline, distillate, oils, and residual oil. Paper companies use process steam to dry wood pulp. The steam needs of industry vary widely, but usually industrial processes require relatively low-pressure, low-temperature steam (frequently in the neighborhood of 150 psi, 365 degrees F).

Steam needs of ELCON member companies have been met by cogeneration facilities for many years. For example:

Herbert Dow, founder of The Dow Chemical Company, installed his first wood-fired cogeneration operation in Midland, Michigan in 1897. Dow Chemical has built and operated cogeneration at most of its large integrated facilities around the world ever since.

- Bethlehem Steel Corporation has collected blast furnace gas from blast furnaces since the turn of the century. This gas is fed into boilers to raise steam and electricity. Bethlehem Steel generates more than 100 MW in four boilers and turbines by this process at its Sparrows Point facility in Baltimore. The generating level is determined according to economic dispatch rules.
- A.E. Staley Manufacturing Company built a coal-fired power house generating 2½ MW in Decatur, Illinois, in 1929. Staley requires steam for corn wetmilling in the manufacturing of corn starch and sweeteners.
- Anheuser-Busch has been cogenerating at the St. Louis brewery for over 50 years. Coal, natural gas and oil are used to fuel six boilers which provide steam to five turbine-generators capable of generating approximately 25 MW. The steam is then extracted from the turbines at various pressure for use in brewing and packaging.

C. Market Forces and the Electric Utility Industry

Although ELCON companies have cogenerated for many years, changes in market forces are forcing them to consider new and reconsider the expansion of existing, projects. Why?

From the turn of the century to about 1970, industrials moved from generating to purchasing electricity. Technological developments allowed utilities to build larger generating units with lower heat rates. Stable prices, low interest rates, economical fuel and efficient construction programs, combined with increased engineering efficiencies and enhanced transmission and distribution networks, drove the unit cost of electricity downward.[1]

Throughout this period, industrial electricity consumption increased dramatically. Industrials found it economical to purchase rather than to generate to meet their electricity needs.

The good times ended, as we know, around 1970 when:

- o Interest rates rose to record heights, substantially increasing the capitalized carrying costs of new construction projects.
- o Inflation increased not only the costs of new utility facilities but also the operating costs of existing utility facilities.
- o Fuel costs, particularly oil costs, rose dramatically.
- o Environmental concerns substantially increased both the costs of mining, transporting and burning coal and the length of time required to build a coal-fired generating station.
- o The efforts of vocal antinuclear advocates, combined with other safety concerns, more than doubled the time required to build a new nuclear generating unit and resulted in very costly backfitting orders for existing, operating units.

Combined, these ominous developments led to rapidly rising electricity costs. We entered a new, political era in which the prevailing attitude was one of protecting residential customers.

The attempts to protect residential customers were quite effective. Indeed, industrials presently are required to pay far more in electricity costs than they should pay.

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[1] The views in this section are expressed in much more detail in: Anderson, John A. "Marketplace Pricing Will Strengthen The Electric Transmission System." Public Utilities Fortnightly (May 29, 1986), pp. 33-38. A copy is attached.

Non-discriminatory electricity pricing requires levelized rates of return for all customer classes. By definition, if the rate of return for one customer class exceeds the overall system rate of return, that class subsidizes other customers.

ELCON recently measured the existing cross-class subsidy. We asked three consultants to provide us hard data on existing rates. They compared the after-tax rate of return on investment for industrial and residential customers with the system average rate of return. They found:

- The rate of return provided by industrials exceeds that of residentials in 79 of the 84 cost-of-service studies (or in 94% of the studies).
- Nine times out of ten (in 76 of the 84 studies) the industrial rate of return exceeds both the residential and the system average rate of return.

ELCON published the results of this research in our "Cost-of-Service Profile" (copy is attached). This survey shows that industrial electricity consumers pay more than $2.5 billion annually in subsidies to other ratepayers.

This subsidy is very substantial: $2.5 billion is roughly equal to the negative balance of trade with England or Italy. It is enough to pay the annual electric bills of more than 4 million homes or nearly twice the number of residential customers in New York City.

D. The Industrial Reaction

Industrials reacted to rising electricity costs and the disproportionate increases in rates just as you would expect them to react -- that is, in line with market forces.

Electricity is simply a resource -- a raw material -- to industrials. They reacted to increased electricity prices just as they would to a price increase in any other resource. They tried to:

- protect themselves from overcharges,
- invest in energy conservation,
- substitute other fuel, and
- use alternative electricity supplies.

D.1. Protection from Overcharges:

To protect from overcharges, industrials started to view electricity as a controllable cost item. They set up tracking systems to monitor future supplies and prices. They developed extensive engineering and legal expertise. They began to make managers responsible for electricity cost control.

They also decided to participate actively in utility rate cases. As they became more accustomed to the procedures, they organized into groups with common interests to intervene with a united front.

They began by concentrating on rate design issues. But, as the dollars at stake grew, industrials broadened their intervention to include all aspects of the rate case.

D.2. Conservation:

Conservation is the more efficient use (not simply decreased use) of a resource. Industrial firms have spent hundreds of millions of dollars on conservation projects. They are continuing these conservation efforts today.

The first steps involved the obvious: repair leaks, turn off equipment when not needed, re-insulate, etc. Later, entirely new processes were developed and implemented. For example, chlorine can now be produced by a membrane process that requires approximately 2,000 KWH/ton. Earlier production techniques, using mercury cells, required approximately 3,000 KWH/ton. Additionally, the membrane process produces an output with a substantially higher caustic content, thus fewer BTUs are required to further concentrate the product for shipment.

Although industrials have come a long way, many suggest that the conservation process is just beginning. Future developments will depend largely on the price signals that are sent to customers.

D.3. Substitutes:

There are few substitutes for electricity. For example, the alternative to electromechanical motor drive is direct conversion of fuels into mechanical energy. The equipment that converts fuel to mechanical energy (diesel engines, steam generators, etc.) is relatively costly to purchase and maintain.

In some instances, industrials can economically dispatch their manufacturing plants to shift fuel consumption. For example, a steel company with idle blast furnaces can vary its gas/electricity ratio to some extent by increasing production with blast furnaces and reducing production with electric arc furnaces. This potential is limited, however, by both technical and economic considerations. A far greater concern, however, is that foreign imports can displace domestic electricity consumption.

D.4. Alternative Supplies -- Purchases:

Local power, when it is relatively expensive to generate, can be displaced with power generated by more efficient, distant sources. Similarly, excess cogenerated power can displace expensive utility generated power. However, such displacement requires "wheeling" which is the use of transmission facilities of one electric system to transmit power of and for others. Utilities refuse to wheel.

Market forces are developing tremendous industrial interest in wheeling. The reaction is similar to that experienced with contract carriage of natural gas.

D.5. Alternative Supplies -- Generation

Changes in market forces also drove industrials to reconsider their cogeneration opportunities. They responded with vigor. For example:

o General Motors Corporation installed its first cogenerating unit about 50 years ago. It was a 7.5 MW coal plant and is still running. A second unit -- a 10 MW gas turbine system -- was installed last year. A third system will be completed this summer. It is a 27 MW unit using a circulating fluid bed coal boiler. A fourth unit -- a 4 MW turbine -- was just ordered. After 50 years of reliance on purchased power, GM says on-site generation looks good again.

- Diamond Shamrock Chemicals Company installed a 225 MW gas-fired combined cycle cogeneration facility at its Battlefield, Texas, chlorine plant in 1982. This unit provides all the steam needs and most of the electric requirements of the industrial complex. It has been very reliable. Indeed it exceeded the output requirements specified in the contract negotiated with Houston Lighting and Power for all peak periods in 1984 and 1985.

- Bethlehem Steel Corporation has been cogenerating for many years. Starting in late 1987, a new turbine installation in the blast furnace gas piping will extract kinetic energy from the gas by generating electricity. This generation will augment the existing facilities which use blast furnace gas to generate both steam and electricity.

III. PURPA

Prior to 1978, industrials wishing to cogenerate faced four major obstacles:

- Utilities often refused to interconnect with cogenerators.

- Utilities were often unwilling to purchase the industrial's excess power or were willing to purchase such power only at unreasonably low rates.

- Some utilities charged discriminatory rates for backup, supplemental and maintenance power.

- A cogenerator which provided electricity to a utility could be considered a public utility and, as such, might be subject to extensive state and federal regulation.

Congress passed the Public Utility Regulatory Policies Act of 1978 (PURPA) at least partially in an attempt to remove obstacles to cogeneration development.

A. PURPA Benefits

PURPA, and the Federal Energy Regulatory Commission (FERC) rules implementing the Act, provide certain benefits to "qualifying facilities" (QFs). These benefits include:[2]

A.1. Interconnections

Prior to PURPA, comprehensive Federal Power Act (FPA) provisions allowed utilities to resort to protracted hearings to avoid interconnecting. PURPA provided FERC with the authority to order interconnections. The FERC rule implementing this provision requires the QF to pay interconnection costs.

A.2. Rates for purchases of QF power

PURPA changed the way that regulators are to view utility purchases of energy and power from QFs.

Rate regulation traditionally allows utilities an opportunity to recover reasonable costs and earn a fair rate of return on investment. This traditional ratemaking process requires regulators to examine the books and records of the utility to determine whether or not the costs incurred are reasonable.

PURPA does not require regulators to study the books of the cogenerators to determine the cost of production. Rather PURPA requires regulators to look at changes in the _utility's_ costs caused by the utility's purchase of cogenerated power.

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[2] These benefits are discussed in depth in the publication:
(Previous Footnote Continued)

PURPA does not allow utilities to purchase cogenerated power at rates that exceed the costs that the utility avoids by purchasing this power. PURPA further requires that the FERC rules implementing Sections 201 and 210 shall ensure that the rates for purchase of cogenerated power (1) shall be just and reasonable to the consumers of the electric utility and in the public interest, and (2) shall not discriminate against the QF.

The FERC rule lists several factors which may be taken into account in calculating avoided costs. These factors include the duration of the obligation, termination notice requirement and sanctions for noncompliance, the expected reliability of the qualifying facility, the ability of the utility to dispatch the qualifying facility, and the extent to which scheduled outages of the qualifying facility can be coordinated with scheduled outages of the utility's facilities. State regulatory authorities were required to implement a cogeneration (and small power production) program by March 19, 1981, that conforms with the FERC rule. The specifics of each state's rules differ substantially, although most rules offer fixed rate tariffs for QFs of 100 KW or less, as required by the FERC rule. Most states also have formulated either a generic avoided cost rate

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(Previous Footnote Continued)
Industrial Cogeneration: A Background Paper, Electricity Consumers Resource Council, Washington, D.C., June 1983. pages 16-32. A copy of this paper is attached.

or a methodology for calculating avoided costs on a case-by-case basis for QFs larger than 100 KW.[3]

A.3. Rates for sales to QFs

PURPA requires the FERC to prescribe rules relating to power sales by utilities to cogenerators. These rules are intended to both encourage cogeneration and require electric utilities to sell electric energy to QFs. PURPA states that the FERC rules are to ensure that the rates charged for such power sales shall (1) be just and reasonable and in the public interest, and (2) not discriminate against the QF.

The FERC rule implementing PURPA Section 210 requires that, upon the request of a QF, each electric utility shall provide supplementary, backup and maintenance power at just and reasonable, nondiscriminatory rates. Additionally, the FERC rule requires that the rates for sales of backup or maintenance power shall (1) not be based upon an assumption unsupported by factual data that forced outages or other reductions in electric output by all QFs on a system will occur simultaneously, or during the system peak, or both and (2) take into account the extent to which scheduled outages of the QFs can be usefully coordinated with scheduled outages of the utility's facility.

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[3] Energy Users News conducted a survey of each state's avoided costs rates. This survey is attached.

A.4. Exemption from regulations

Prior to PURPA, industrial cogenerators could be subjected to public utility regulation if they produced and sold electric power. The threat of cumbersome and expensive public utility regulation deferred the development of cogeneration.

The FERC rules exempt QFs from certain federal and state laws and regulations including:

- A qualifying cogeneration facility is not considered an "electric utility company" as defined in the Public Utility Holding Company Act of 1935, and is therefore exempt from the Act.
- Qualifying cogeneration facilities are exempt from certain burdensome provisions of the Federal Power Act.
- Qualifying cogeneration facilities are exempt from the ratemaking and electric utility financial and organizational regulations authorized under state laws, except for those state laws and regulations which implement the provisions of PURPA Section 210 and the final regulations under PURPA Section 210.

B. Impacts of PURPA

In 1978, Congress recognized that monopolistic utilities were able to block the development of efficient cogeneration facilities. PURPA was enacted, in part, as an attempt to neutralize the utilities' monopolistic advantages, thus evening the bargaining positions of cogenerators and utilities.

PURPA has worked quite well. Between 1980 and 1985, the FERC received nearly 2,000 requests for QF status representing nearly 30,000 MW of capacity. Utilities would be able to block most of this QF development without PURPA.

IV. PURPA MYTHS

Despite its resounding success in stimulating efficient cogeneration, utilities propose changes in PURPA attributable to certain alleged "problems." These alleged "problems" largely are myths. Let us dispel some of these myths.

A. Myth #1: Cogeneration causes reliability problems.

Utilities often allege that cogeneration facilities are unreliable; they may or may not produce electricity when scheduled; and their owners may decide to close the manufacturing plant and go out of business.

In fact, the opposite generally is true. The cogeneration facilities owned and operated by industrials such as those belonging to ELCON are very reliable. Indeed, such facilities actually may increase the reliability of a host utility.

The higher reliability is attributable to several factors. First, cogeneration facilities of ELCON member companies usually operate a larger number of hours per year (they have a higher "capacity factor") than do utility generators. They don't break down as often. They have to be highly reliable, since forced outages -- unplanned stoppages -- would require all (or at least a large portion) of the manufacturing process to stop unexpectedly.

Second, cogeneration facilities usually are much smaller than utility generating units. Thus, a forced outage by one cogenerator represents a much smaller percentage of the total generation than the base-load unit. In statistical terms, reliability increases with the number of shafts (generators) since the probability that all shafts would go out at the same time is inversely related to the number of shafts.

Third, cogeneration capacity is normally located close to the utility's system loads and thus can effectively enhance the system stability by providing efficient reactive power to stabilize system voltage. Thus a utility can increase its systems stability and minimize transmission losses without the expensive investment in static capacitors. An example of the significance of such savings is reflected in a 20 year transmission study issued by Houston Lighting and Power (HL&P) in November, 1984:[4]

> "If there is no cogeneration in the next 20 years, HL&P will need about 2800 MVAR of capacitors in addition to the existing system to receive the remote and import power. HL&P will need approximately 400 MVAR of capacitors if there is a 5500 MW of cogeneration capacity at .9 power factor (PR) and the system is operating at export mode and most of HL&P internal generators are on line. In addition, many of the required capacitor banks will be in 345 KV ratings and need to be switched off at light load conditions."

Fourth, industrial cogeneration facilities sometimes can be called upon to provide backup power to the grid in emergencies. Obviously, such situations must be agreed upon on a case-by-case basis prior to the emergency. However, the benefits to the utility can be significant. For example:

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[4] Engineering Planning Division, Houston Lighting and Power Company, "HL&P Transmission System in the Year 2004 for Different Scenaries, November 1984, pages 1-2.

- Bethlehem Steel Corporation and Baltimore Gas and Electric have had a contract in place for 20 years that requires Bethlehem to run its more than 100 MW of cogeneration capacity at Sparrows Point on oil or natural gas and provide the energy to BG&E if blast furnace gas is not available in emergencies. This will happen several times per year, usually during the summer. Bethlehem has always been able to comply with these "maximum emergency" requests by BG&E with very high reliability.
- Air Products and Chemicals Incorporated provided more than 20 MW to the City of New Orleans after an unusually severe cold wave forced outages of many of New Orleans Public Service generators. This industrial power saved segments of New Orleans from almost certain blackouts.
- During the last emergency declared in the ERCOT interconnect area in Texas on May 16, 1985, non-firm cogenerators along in the HL&P service area contributed a minimum of 222 MW of power despite the lack of any contractual commitment to do so. This was in addition to the over 750 MW being provided at the time from firm contract cogenerators.

In sum, cogeneration does not cause reliability problems for utilities. Admittedly, certain units may have operating characteristics that are inconsistent with the host utility's generation and load.[5] However, other units, particularly those similar to the ones operated by ELCON member companies, actually may improve the reliability of a utility.

B. Myth #2: PURPA requires utilities to pay cogenerators rates that equal or exceed avoided costs.

This simply is not true.

PURPA does not mandate any purchase rate. Rather, it places a ceiling on rates equal to the utility's avoided cost recognizing that payments in excess of the actual costs avoided must cause some economic harm.

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[5] This may be particularly true for certain non-cogenerator QFs. Our comments, as mentioned above, are limited strictly to cogenerators.

Actual rates paid for purchased QF power are negotiated on a case-by-case basis for large cogenerators. Utilities and cogenerators negotiate contracts at arm's length taking into consideration the length of the contract, termination procedure penalties for non-compliance, the ability to dispatch, timing of scheduled outages, etc. In nearly every instance, large QFs are paid less than avoided costs.

Specifically, in the Gulf coast area of Texas, where numerous petrochemical facilities have become or are planning to become cogenerators, an abundance of efficient economical cogeneration has lead to substantial savings to all ratepayers in the area. HL&P purchased firm capacity in 1985 from three recently signed contracts. Diamond Shamrock Chemicals, Dow Chemical and Bayou Cogeneration provided 750 MW of capacity.

HL&P analysis of the benefit of these contracts is included in its 1986-87 Energy Efficiency plan:[6]

> "Our estimate of the net present value of the projected savings to our customers, over the ten year term of our firm capacity contracts with Dow, Diamond Shamrock and Bayou, is $148,707,000. This is our estimate of the savings attributable to HL&P's success in negotiating capacity payments at levels which were lower than our estimate of avoided capacity costs."

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[6] Houston Lighting and Power Company, "Energy Efficiency Plan," November 27, 1985, section D. page 1.

This point is further documented in a recent study prepared for DOE.[7] Specifically, this report states:

> Most large QFs must negotiate rates somewhat below full avoided cost to obtain concessions for the utility in certain contractual matters not guaranteed under Section 210 (e.g.,levelized payment, long-term contracts, etc.) but which are frequently necessary to obtain project financing. For example, in 1982, the Southern California Edison Company (SCE) testified that the average purchase for rate contracts it had negotiated with 60 QFs for over 1000 MW of capacity, was 93 percent of full avoided cost. The full avoided cost rate, SCE noted, was appropriate and paid for projects involving "emerging technologies" (i.e., solar, wind, and geothermal).
> Similarly, Houston Lighting and Power Company has signed contracts for over 500 MW of cogeneration capacity at rates reportedly below its full avoided costs. As noted below, Maine utilities have negotiated over 150 MW of QF contracts under a quasi-competitive bidding scheme at rates below avoided costs as calculated under applicable state regulation. Similar purchase agreements at rates below avoided cost have been negotiated by a number of other utilities in other jurisdictions.

There certainly are examples of utilities purchasing QF power at rates that exceed avoided costs. These examples include purchases from "standard offers" (such as in California and Idaho), according to state-legislated rates (such as New York's 6¢/KWH law).

However, these examples (1) often are self-correcting and (2) are not the creatures of PURPA. Regarding the former, the regulatory commissions of California and Idaho recently reconsidered earlier orders. They now require substantially lower payments for the purchase of QF power.

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[7] Pfeffer, Lindsay and Associates, Emerging Policy Issues in PURPA Implementation, a report prepared for the U.S. Department of Energy, Contract No. PEACOI-83-PE-70404, March 1986, page 5.37.

Specifically, several years ago the Idaho Public Utilities Commission ordered Idaho Power Company to pay 70 to 80 mills/KWH for purchased cogeneration and small power production (C&SPP) power. This price signal was very attractive to prospective C&SPP developers. Idaho Power signed for renewing approximately 55 MW -- or 2-3 percent of their total load. Of more importance, other C&SPP developers indicated that another 200 MW may be installed.

Idaho Power took several steps to have the rate adjusted downward. The Commission responded. First, the Commission issued an interim order in 1985, lowering the rate to approximately 40 mills. Second, the Commission issued a final order setting the rate at 20-48 mills, depending upon the date signed and the duration of the contract.[8]

Of more importance, not only are above-avoided-cost rates not created by PURPA, they are in violation of PURPA. This act specifies that avoided cost is the ceiling for rates for purchase of QF power. Individual state regulatory commissions balance the needs and desires of their citizens and utilities in implementing the PURPA provisions in their states. PURPA has not caused above-avoided-cost rates, and changes in the federal law will not remedy the situation.

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[8] Idaho Public Utilities Commission, "In the Matter of Application of Idaho Power Company for New Cogeneration/Small Power Production Rates," Case No. V-1006-248, Order No. 20402, April 18, 1986, p.23.

C. Myth #3: PURPA gives the states unfettered authority to set rates for the purchase of QF power.

PURPA does not provide the FERC the authority to second-guess state PUC decisions. Nor should it.

But neither does PURPA give the states the authority to set rates above avoided costs. Indeed PURPA, along with other federal and state laws, requires state commissions to set non-discriminatory rates. Clearly, above-avoided-cost rates are discriminatory and should be challenged where they occur.

However, PURPA has not given states the authority to set above-avoided-cost rates. Where states have set rates above avoided costs, they have violated PURPA. Changes in PURPA will not remedy the situation.

D. Myth #4: PURPA increases costs for other consumers.

By definition, properly implemented PURPA rates cannot increase costs for other customers.

Improper state implementation may require consumer subsidies to cogenerators. However, a recent Department of Energy study concludes that this has not happened to a measurable degree.[9] Specifically, the DOE recently asked Hagler, Bailly to critically evaluate the rate impact of cogeneration development on utilities with (1) a high level of cogeneration and (2) high buyback rates. Hagler, Bailly concluded as follows:

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[9] Hagler, Bailly and Company, Potential Detrimental Effects of Cogeneration Development on Utility Costs, a study prepared for the Office of Industrial Programs, U.S. Department of Energy, Contract No. DE-AC01-84CE40646, February 1986.

> In summary, the analysis indicated that any adverse or detrimental effects of cogeneration (and small power generation) to utility customers should not exist over the long term. In principle, the mechanisms either have been or are being implemented to ensure that the prices paid for cogenerated electricity do not exceed a utility's actual avoided cost over a reasonable period of time. If one assumes that avoided costs are accurately determined and applied, as is the premise of this study, the utility and its customers should be indifferent in the long run to the amount of cogenerated electricity purchased. In the short run, however, the cost of purchasing cogenerated electricity could increase average electricity costs, forcing utility customers to pay higher rates.

E. Myth #5: PURPA rates artificially stimulate cogeneration investments.

ELCON member companies base their economic feasibility studies on estimates of displaced power costs, not on rates that are based on PURPA.

Cogeneration investments of our members are designed and built to have very long lives. PURPA rates are perceived as potentially unstable. "What Congress giveth, Congress can taketh away."

Our members study carefully each utility that provides service to each manufacturing location. Estimates are made of future generating costs and industrial rates. Decisions to invest in cogeneration are based on the economic savings attributable to reduced purchases of utility generated power.

Ironically, this market-oriented decision process often drives industrials to add new capacity in precisely those areas where excess utility capacity now exists. This is because rates often rise substantially when expensive new capacity is completed and added to rate base. Furthermore, industrial rates usually rise even faster than other rates as regulators try to shield residential customers from rate increases, thus exacerbating the situation.

The impact of rate increases is particularly substantial when the capacity additions are not needed -- as is often the case today. Specifically, electric utilities now report that the national average reserve margin is 33.9 percent. It is expected to fall only to 25.5 percent by 1994. Table 1 presents data provided by utilities describing those capacity conditions.

Seven of the nine North American Electric Reliability Council (NERC) regions today have reserve margins in excess of 30 percent. Utilities project reserve margins for these regions to remain above 20 percent throughout the mid-1990s without cogeneration additions.

F. Myth #6: Cogeneration encouraged by PURPA displaces more efficient utility base-load generating units.

From a consumer standpoint, the opposite often is the case.

Large, central-station generators usually operate at a higher engineering efficiency -- a lower heat rate -- than smaller, central-station generators. Even so, cogeneration facilities often produce electricity at a higher engineering efficiency than utility generators.[10]

But of more importance to electricity consumers, large,utility central-station generating units operate at far less economic

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[10] This point is discussed in more detail in the paper Industrial Cogeneration, op. cit., attached to this testimony.

TABLE 1

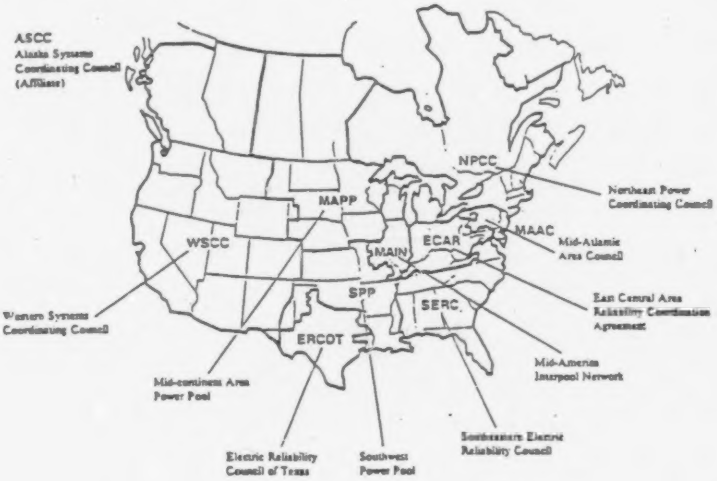
Peak Demand Grows as Forecasted by each NERC Region

Reserve Margins in % of Peak Demand

84-94 Peak Demand Growth Rate-%	NERC Region	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
2.11	ECAR	36.8	36.5	40.4	38.0	36.3	34.8	33.7	31.4	31.0	30.3	29.0
3.58	ERCOT	19.6	15.3	16.0	23.7	22.2	21.3	20.8	20.5	19.7	19.7	19.1
1.04	MAAC	30.3	30.1	31.8	33.4	31.8	29.8	28.4	29.4	29.3	29.4	27.3
1.42	MAIN	18.3	30.0	28.0	34.9	35.7	33.6	31.6	29.5	27.1	25.2	23.1
2.53	MAPP-US	36.3	31.2	29.7	27.4	27.4	24.4	21.8	19.2	17.0	14.1	13.3
1.78	NPCC-US	34.5	28.9	31.6	35.3	33.0	31.1	29.2	27.7	25.1	25.5	22.9
2.70	SERC	36.6	33.6	33.2	34.3	32.5	33.4	30.2	30.9	28.4	27.6	25.3
2.68	SPP	32.5	36.5	37.6	33.9	30.6	26.6	24.0	24.3	22.3	22.7	21.9
2.26	WSCC-US	43.5	38.4	42.9	41.6	41.4	40.1	37.6	36.9	36.0	33.9	33.2
2.31	NERC-US	33.9	32.6	34.3	34.9	33.5	32.2	30.0	29.4	27.9	27.0	25.5

SOURCE: Electric Power Supply and Demand, 1985-1994, North American Electric Reliability Council, Princeton, NJ, 1985.

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL


ASCC
Alaska Systems Coordinating Council (Affiliate)
NPCC
Northeast Power Coordinating Council
MAPP
MAAC
Mid-Atlantic Area Council
WSCC
ECAR
MAIN
East Central Area Reliability Coordination Agreement
SPP
SERC
Western Systems Coordinating Council
ERCOT
Mid-American Interpool Network
Mid-continent Area Power Pool
Southeastern Electric Reliability Council
Electric Reliability Council of Texas
Southwest Power Pool

efficiency than cogeneration units (or perhaps even small utility generating units). Consumers observe the price charged for electricity, not the number of BTUs required to generate a kilowatt hour.

Society is better off with generators that produce the lowest cost electricity than with very costly units that happen to have lower heat rates. The displacement of very costly utility generators, when and if it occurs, thus makes economic sense.

G. Myth #7: PURPA requires a utility to buy cogenerated power whether it needs it or not.

Section 210 of PURPA requires utilities to either purchase electricity from QFs or wheel it to another utility. The price paid for the purchase should not exceed the avoided costs of the purchasing utility. PURPA does not require capacity payments if capacity costs are not avoided.

Utilities always can use energy. No consumer is harmed in any way as long as energy payments do not exceed avoided costs.[11]

H. Myth #8: PURPA prohibits utility ownership of cogeneration.

This perhaps is the ultimate fallacy.

PURPA places no limit on utility ownership of cogeneration facilities. If cogeneration is such a good deal, utilities can and should develop cogeneration projects. In fact, they have an obligation to invest in cogeneration if it is the lowest cost way to meet their consumers needs.

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[11] By definition, this statement is correct. However, in certain extreme cases, implementation complexities may be substantial. For example, the actual costs avoided for a hydro-based utility may be very low in times of high water flows. Such conditions should be considered carefully by the appropriate regulatory commission in setting the level for purchase

PURPA limits utility ownership of unregulated QFs to less than 50 percent to protect consumers from possible monopolistic exploitation. Removal of this cap would _de facto_ deregulate a portion of a utility's assets without providing offsetting competitive constraints. This could harm utility customers by:

- Reducing the incentive to lower avoided costs.
- Reducing the incentive to install an optimal generation mix.
- Diverting capital and managerial resources from necessary utility functions to unregulated operations.
- Reducing the effectiveness of state regulatory commissions since unregulated assets are not jurisdictional.
- Providing a utility-owned cogeneration facility an unfair advantage over a non-utility-owned facility in contract negotiations.

The last point may be the most significant. Contract negotiations are very complex and cover many points. It is very difficult to prove unfair actions in such a complex arena. Cogenerators do not believe that most utilities would deal on an arms-length basis with wholly owned subsidiaries. This lack of trust is well formed. Many utilities have taken strong positions opposing cogeneration facilities in order to be able to build less economically efficient capacity of their own. Changing the 50 percent cap would allow them to take similar positions opposing non-utility owned QFs.

I. Myth #9: The operating and efficiency standards specified by PURPA are flawed.

PURPA specifies no operating or efficiency standards.

The FERC rules implementing PURPA require "sequential" use of energy in order to receive qualifying status. These rules also specify that at least 5 percent of a QF's total energy output be in the form of useful thermal energy. Additionally, the FERC rules require that the sum of the useful power output and one-half of the useful thermal output be greater than 42.5 percent of the QF's energy consumption.

An increasing number of QF applications employ "extraction turbines" which maximize the electricity to steam ratios. Extractor turbines are similar in design to conventional utility generating turbines; steam simply is extracted from the turbine for some heating use.

Concern has been raised that certain developers are building extraction turbines designed just to meet the FERC rules. These units may not produce benefits envisioned by the creators of PURPA. Yet these units qualify for QF status and, it is alleged, displace more efficient utility generation.

ELCON has studied this issue carefully. We state unequivocally that it is not a PURPA problem.

If there are problems with the operating and efficiency standards, they should be studied, debated and corrected. But the proper forum is FERC. The FERC can change the standards, if such changes are found to be necessary, with a rulemaking.

J. Myth #10: Economic efficiency and consumer equity require competitive bidding for available capacity credits.

It sometimes is alleged that competitive bidding would assure that the most economic resources would be developed first. On the surface this idea seems attractive, especially when the amount of QF capacity offered to a utility exceeds the need for capacity in a given time frame.

ELCON member companies are very familiar with the competitive bidding process. They use competitive bidding in most of their purchasing and often sell products competitively to their many customers.

However, simple assertions that competitive bidding should be applied to purchases of cogenerated power fail to appreciate the complexities of both (1) the process by which cogeneration facilities are determined "economic" and (2) the power granted a utility with its "exclusive service territory." Each is discussed below.

First, cogeneration projects come in many sizes and configurations. They range from very small, "off-the-self" packaged units to large, custom engineered and constructed facilities. Realized efficiencies depend upon a number of factors, including uses and load curves for both electricity and steam, fuel types and costs, actual operating characteristics, and many others.

A decision to invest in a cogeneration facility necessarily must follow a careful balancing of expected costs and revenues.

Cost estimates for "packaged" or "off-the-shelf" units may be obtained quickly and without great expenditures of time or money.

Cost estimates for custom facilities require detailed engineering estimates and require a time period involving months.

Corporate executives must have some assurance that funds committed for engineering studies will benefit the corporation. Use of the bidding process would substantially reduce (or perhaps eliminate) corporate bids based on custom-engineered cogeneration facilities.

Bids would be received for off-the-shelf cogeneration equipment however, since cost estimates are quicker and easier to formulate.

Second, the exclusive service territory of a utility gives it a unique and substantial power over a cogenerator. By refusing to wheel power to other prospective buyers, utilities become "monopsonists" -- single buyers of cogenerated power.

By refusing to wheel backup or maintenance power from other sources, utilities become "monopolists" -- single sellers of necessary power to a cogenerator.

Congress recognized the monopsony and monopoly powers granted to utilities by the governmentally guaranteed service territory. Congress tried to "level the playing field" with PURPA.

PURPA required utilities to either: (1) buy all the energy produced by a cogenerator, or (2) wheel the energy to a distant utility.

The choice of options is strictly controlled by the utility.

The cogenerator has no influence over the utility's decision. Neicher does the cogenerator have any option or recourse if the utility makes a decision that is harmful to the cogenerator. PURPA thus changes neither the monopsony nor the monopoly status of the utility.

Allowing utilities to institute "competitive" bidding without giving cogenerators the ability to sell their power in a wider market than just that of the host utility de facto strips the cogenerator of the bargaining power that PURPA tried to give.

Competitive bidding may be a good idea, in theory. Practically, however, "competition" can't work when there is only one buyer. Any implementation of competitive bidding must be accompanied with access to other potential buyers.

V. PROBLEMS FACING COGENERATORS

While many alleged cogeneration "problems" actually are myths, real problems exist.

A. Backup, maintenance and standby power rates

PURPA requires that utilities offer cogenerators backup, maintenance and standby power at non-discriminatory rates. However, cogenerators continually find it difficult to negotiate contracts with obstinate utilities.

This problem is not one attributable to PURPA. The problem usually is a lack of (or a lack of adequate) state oversight. PURPA provides the legal basis. It is up to the states to act.

B. Refusal to wheel

Industrial cogenerators often are hit with a "double whammy." They are paid less than avoided cost for cogenerated power sold to a utility at one location, then charged far more than cost-of-service for utility-generated power purchased at another location.

A logical solution to this dilemma would be to allow the industrial to consume the power he generated at one location at another plant site. This would reduce, if not eliminate, the need to negotiate contracts both for sales of cogenerated power and purchases of utility-generated power. However, it requires that the power wheeled from one loactation to the other. Utilities can and do refuse to wheel.

Individual states are studying the issue of the wheeling of cogenerated power -- and some are taking action. For example:

- o Texas now orders utilities that do not need capacity to wheel cogenerated power to other utilities in Texas. Indeed, Houston Lighting and power now wheels 300 MW of capacity from Dow Chemical to Texas Utilities.
- o Florida now orders utilities to wheel cogenerated power. The Florida Commission analyzes the capacity expansion plans of each Florida utility. They identify individual units that were planned, but then avoided, because of cogeneration. The Commission then orders the wheeling of cogenerated power from any location in the state to the utility that avoids construction.
- o The Connecticut General Assembly recently enacted legislation that in part requires electric utilities to transmit energy or capacity from a willing private power producer to a) another electric utility or b) another facility operated by the private power producer.[12]

The issue of wheeling is very complex. It involves far more than movements of cogenerated power. We strongly urge this committee to initiate proceedings on the general issue of wheeling to increase competition, increase efficiencies and lower costs.

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[12] C.G.S. Sec. 16-243a (b) (4).

C. Ownership restrictions

Industrials with different steam-to-electricity load characteristics often would like to build jointly-owned cogeneration facilities designed to meet their combined needs. Extreme care must be taken to be certain that one or both of the industrials is not then classified a public utility and subjected to regulation.

This is not solely a PURPA issue. Rather, it is related to the concept of deregulation of portions of generation. It is affected by both PURPA and the Public Utility Holding Company Act of 1935 (PUHCA). It should be debated in this broad context.

D. Facility Size Restrictions

Qualified cogeneration facilities face no size restrictions. However, small power production (SPP) facilities that are greater than 80 MW may not qualify. Furthermore, SPPs that are greater than 30 MW but no more than 80 MW may qualify for the rate benefits of PURPA but may not be exempted from PUHCA, the Federal Power Act (FPA), or from state laws regarding financial or organizational regulation.

These restrictions raise significant efficiency concerns.[13] Primarily these concerns suggest that some units are deliberately downsized below economically efficient scales in order to qualify or are not built at all.

ELCON recognizes that these size restrictions may negatively impact the development of certain desirable projects. However, changes in (or elimination of) these restrictions must be very carefully considered before the enactment of legislation. We do not believe that enough is known to proceed legislatively at this time. This committee is urged either to initiate oversight hearings on the issue or to request a detailed study of the concerns by the FERC.

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[13] These concerns are described in detail in Pfeffer, Lindsay & Associates, op.cit., pages 10.1-10.7.

FACT SHEET

ELCON

ORGANIZED: January 15, 1976

STRUCTURE: Association of industrial users of electricity

PURPOSE: Promote the development and adoption of coordinated, rational and consistent federal, state and local policies which will assure an adequate, reliable and efficient electricity supply for all users at prices based on the costs incurred in serving customers.

FUNDAMENTAL PRINCIPALS:

- Electric utility rates should be based on the cost of service;
- Adequate short term reliability and long term availability of electricity must be assured;
- Continuing, adequate and reasonably priced fuel sources for generating electricity are important for economic viability, development and growth;
- Electric utility costs should reflect efficient and well-managed utility operations;
- Electric utilities should have the opportunity to earn a fair rate of return in order to be able to meet current and future capital needs; and
- Federal and state regulatory processes should be responsible and timely.

ACTIVITIES:

- Represent industrial viewpoints in a constructive dialogue among all electricity users, suppliers, regulators, state and federal government bodies in a factual, objective manner;
- Promote awareness of why electricity costs have increased and possible ways to contain costs;
- Build an objective data base which identifies current and anticipated electricity problems and suggests practical solutions to these problems.

CURRENT MEMBERSHIPS:

Air Products and Chemicals, Inc. (Allentown, PA)
Anheuser-Busch Companies, Inc. (St. Louis, MO)
Armco (Middletown, OH)
Bethlehem Steel Corporation (Bethlehem, PA)
Cone Mills Corporation (Greensboro, NC)
Corning Glass Works (Corning, NY)
Diamond Shamrock Chemicals Company (Irving, TX)
Dow Chemical U.S.A. (Midland, MI)
E.I. du Pont de Nemours & Company (Wilmington, DE)
FMC Corporation (Chicago, IL)
General Motors Corporation (Detroit, MI)
Hercules Incorporated (Wilmington, DE)
Hershey Foods Corporation (Hershey, PA)
Kaiser Aluminum & Chemical Corporation (Oakland, CA)
MG Industries (Valley Forge, PA)
Olin Corporation (Stamford, CT)
Owens-Corning Fiberglas Corporation (Toledo, OH)
PPG Industries, Inc. (Pittsburgh, PA)
A.E. Staley Manufacturing Company (Decatur, IL)
Stauffer Chemical Company (Westport, CT)
Union Carbide Corporation (Danbury,CT)

ELECTRICITY CONSUMERS RESOURCE COUNCIL
1707 H Street, N.W., 10th Floor, Washington, DC 20006
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Marketplace Pricing Will Strengthen The Electric Transmission System

By JOHN A. ANDERSON

This article is written from the point of view of large industrial users of electricity for whom energy costs are significant components of total production costs, and possible determinants of success in competitive markets. It reveals the importance which industrial customers of electric utilities ascribe to obtaining power supplies at lowest cost in a more competitive electricity market. It also voices a demand on the part of industrial users that transmission services be made more widely available, through regulatory action if need be, to facilitate acquisition of electricity supplies from low-cost sources.

The member companies of the Electricity Consumers Resource Council consume approximately 10 per cent of all electricity sold to industrial customers and nearly 5 per cent of all electricity consumed in the United States. They require an adequate and reliable supply of electricity at reasonable prices; thus, they have a continuing interest in all aspects of the production, pricing, and delivery of electricity.

ELCON members are particularly interested in proposals for marketplace pricing of electricity because they know the marketplace and strongly believe in it. They have to contend there every day. They believe that the interactions of supply and demand determine most equitably, efficiently, and productively answers to critical economic questions such as: What is to be produced? Who is to produce it? And how is the production to take place?

Market forces work better in some industries than in others. We expect, for example, that market forces would work better in industries composed of many buyers and sellers than in industries with few of one or the other. But that does not mean that market forces do not play a part in industries that traditionally have been viewed as monopolistic or monopsonistic.

John Anderson is the executive director of the Electricity Consumers Resource Council. Prior to joining ELCON, he was a professor of economics at the University of South Florida and a consultant. He served on the Presidential Commission on Federal Paperwork and was senior economist with the Motor Vehicle Manufacturers Association. **Dr. Anderson** received MS and PhD degrees from the University of Florida with concentrations in public utility economics and industrial organization.

The relevant question is *not: Will* the market prevail? Indeed, the market has shaped and will continue to shape electricity policies and regulatory decisions. Rather, the relevant questions are: How will regulators and policymakers be influenced by market forces in the future? And: Will utilities, consumers, and regulators attempt to benefit from market pressures or, alternatively, try to oppose the (in my opinion) inevitable evolution to a more market-oriented electric industry?

This article is organized as follows: First, it discusses briefly how market forces have influenced previous regulatory and industrial electricity consumption decisions. (The bottom line is that market forces prevailed in the past, although responses to market forces changed as market conditions changed.) Then, it offers a view of the future. I do not suggest that my crystal ball is any clearer than others. Rather, I suggest that structural characteristics of the industry will force changed behavior in the future.

The Era of Declining Costs – Up to 1970

If we had to label each of the major eras in electrification in terms of how market forces influenced the supply, demand, and cost of electricity, we could pretty fairly sum up the first nine decades or so as the market's golden years. From 1882, when Thomas Edison first supplied electricity service to a small section of lower New York from his Pearl street generating station, until about 1970, the promise of electricity paid off with greater and greater generating efficiencies, increasingly lower rates, and greater use by industry as companies turned from traditional mechanical sources of energy to the controllability, flexibility, and reliability of electricity.

Interestingly, at the dawn of electrification — back when market forces were seldom restrained — *manufacturers* generated nearly 60 per cent of our nation's electricity. Only later did the efficiencies of electric utilities lead to their taking over as our leading suppliers of electricity. In some ways, it seems as though today's interest in cogeneration reflects those early days when industrials supplied so much electricity. Today, as back then, market forces play a major role in the development of self-generation.

Now, despite my interest in free market principles — and before anyone says I am advocating a return to yesterday's policy of laissez faire — let me hasten to add that not everything about the early days was good. At one time, Chicago had 25 to 30 electric companies. It is not hard to see how inefficient and prone to abuse that market must have been. The question is, why did industrials start out as major electric generators and then gradually turn that job over to electric utilities?

Because it made good business sense.

They self-generated when there was no alternative; they got out of the business when there was a reliable, affordable alternative and turned their attention to producing goods and services — the old "make versus buy" concept of engineering economics.

During those golden years, technological developments allowed utilities to build larger generating units with lower heat rates. Stable prices, low interest rates, economical fuel, and efficient construction programs, combined with increased engineering efficiencies and enhanced transmission and distribution networks, drove the unit cost of electricity downward. Utilities implemented highly visible marketing programs ranging from gold medallion homes to reduced rates for electric hot water heaters.

Throughout this period, industrial electricity consumption increased dramatically. Regulatory commissions initiated rate proceedings every few years to "scrutinize" utility costs and approve lower rates. Newspapers (and others) would criticize utilities for "important" things such as excessive country club memberships and rapid turnover of automobiles. Industrials viewed electricity as an uncontrollable cost (and a declining one at that). They were not organized or otherwise prepared to take action. In most cases, they did not even intervene in rate cases.

The Era of Adjustment — 1970 to the Present

The good times ended, as we know, around 1970 when:

- Interest rates rose to record heights, substantially increasing the capitalized carrying costs of new construction projects.
- Inflation increased not only the costs of new utility facilities but also the operating costs of existing utility facilities.
- Fuel costs, particularly oil costs, rose dramatically.
- Environmental concerns substantially increased both the costs of mining, transporting, and burning coal and the length of time required to build a coal-fired generating station.
- The efforts of vocal antinuclear advocates, combined with other safety concerns, more than doubled the time required to build a new nuclear generating unit and resulted in very costly backfitting orders for existing, operating units.

Combined, these ominous developments led to rapidly rising electricity costs. The golden goose laid a lead egg.

We had entered a new era, a political era, in which the prevailing attitude would be one of *overcoming or denying* market forces. If electricity costs hurt people — voters, that is — we would use political or regulatory tools to overcome market forces and ameliorate the "harmful" effects.

The first proposals that emerged to overcome market forces involved direct subsidies to certain blocks of consumers — called lifeline rates. These rates required some customers to subsidize directly the electricity consumption of others. They were opposed, often successfully, on the grounds that state commissions and electric utilities are not equipped to redistribute income equitably.

Creative consultants and other residential advocates then took other tacks. They suggested, for example, that utilities should be required to install and pay for conservation devices on the basis that it is cheaper to "buy" conservation than produce more electricity. They often failed to recognize that the basic assertion is wrong much (or most) of the time. When it is, such programs again require some customers to subsidize others.

The creativity of consultants never ceases to amaze me. When it became obvious that mandated conservation programs often did not reduce residential's costs as expected, proposals surfaced that questioned traditional cost allocation methodologies. Historically, regulators accepted the notion that the size of the fixed plant was determined by the peak demand placed on that system, or anticipated by system planners to be placed on the system. A customer class' fixed cost responsibility thus was a function of the peak demands of that class. Peak responsibility cost allocation methods were used because they made sense, and they worked.

But it soon became obvious to many consultants and regulators that alternative cost allocation and ratemaking methods could result in lower costs to residentials — and, of course, higher allocations to industrials. It is considerably beyond the scope of this article to delve into the intricacies of the numerous alternative cost allocation schemes proposed. Suffice it to say, there were (and still are) many. Some simply picked times to measure peaks that did not comport with the utility's peak. Others asserted that fixed costs were incurred to save energy. They might say, for example, that a utility with a 50 per cent reserve margin would not build a 1,000-megawatt nuclear unit costing $2,000 per kilowatt and more to meet its system peak. Following this "logic," advocates of such capital substitution schemes argued for fixed cost collection as a function of energy consumption rather than peak demand. Finally, some analysts argued that economic theory required regulators to set rates equal to "marginal costs."[1] One may argue at length about the theoretical underpinnings of such proposals and not come to agreement. But, in all candor, the critical problem with the proposals is not the theory. It is the arbitrariness of the revenue reconciliation methods required in implementation. In almost every instance, revenue reconciliation resulted in increased rates for industrials and reduced rates for residentials!

The Industrial Reaction

Industrials reacted to rising electricity costs and the disproportionate increases in rates just as you would expect them to react; that is, in line with market forces. Electricity is simply a resource — a raw material — to industrials. They reacted to increased electricity prices just as they would to a price increase in any other resource. They tried to:

- Protect themselves from overcharges,
- Invest in energy conservation,
- Substitute other fuel, and
- Use alternative electricity supplies.

Protection from Overcharges: To protect from overcharges, industrials started to view electricity as a controllable cost item. They set up tracking systems to monitor future supplies and prices. They developed extensive engineering and legal expertise. They began to make managers responsible for electricity cost control.

They also decided to participate actively in utility rate cases. As they became more accustomed to the procedures, they organized into groups with common interests to intervene with a united front. They began by concentrating on rate design issues. But, as the dollars at stake grew, industrials broadened their intervention to include all aspects of the rate case.

Conservation: It is important to remember that conservation is the more efficient use (not simply decreased use) of a resource. In the area of conservation, industrial firms spent hundreds of millions of dollars. They are continuing these conservation efforts today.

The first steps involved the obvious: repair leaks, turn off equipment when not needed, re-insulate, et cetera. Later, entirely new processes were developed and implemented. For example, chlorine can now be produced by a membrane process that requires approximately 2,000 kilowatt-hours per ton. Earlier, production techniques, using mercury cells, required approximately 3,000 kilowatt-hours per ton. Additionally, the membrane process produces an output with a substantially higher caustic content, thus fewer Btu are required to further concentrate the product for shipment.

Although industrials have come a long way, many suggest that the conservation process is just beginning. Future developments will depend largely on the price signals that are sent to customers.[2]

Substitutes: There are few substitutes for electricity. For example, the alternative to electromechanical motor drives is direct conversion of fuels into mechanical energy. The equipment that converts fuel to mechanical energy (diesel engines, steam generators, et cetera) is costly to purchase and maintain. Additionally, it often creates noise, heat, exhaust, gases, and so forth, and it may be relatively inefficient.

In the short run, some industrials can use excess production capacity to shift fuel consumption. For example, a steel company with idle blast furnaces can vary its gas-to-electricity ratio to some extent by increasing production by one process vis-a-vis another. This potential is limited, however, by both technical and economic considerations. On a longer-term basis, foreign imports can displace domestic electricity consumption.

Alternative Supplies — Generation: Market forces have opened significant new generation opportunities. The extremely high costs of new utility generating units and utility accounting methods that "front-load" capital cost recovery from customers caused industrials to evaluate and re-evaluate carefully the economics of self-generation and cogeneration. It now seems likely that industrial cogeneration alone could exceed 50,000 megawatts by the year 2000. THis power will probably come from a range of facilities — large coal-fired units to small gas-fired turbines.[3]

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[1] Our views on marginal cost pricing are set forth in detail in our filing, "Regulation of Wholesale Electric Requirements Service," Federal Energy Regulatory Commission, Docket No. RM85-17-000, Phase 2, November 4, 1985.

[2] Interestingly, the price signals sent to residential customers often are at odds with conservation goals. For example, often residentials are offered below cost (lifetime) rates, inappropriate cost allocation methods underallocate costs (and thus reduce rates) to residentials, et cetera. Additionally, residentials often are not billed for costs incurred by the utility until a later time; e.g., levelized billing programs. Under such programs, residentials are encouraged to consume more — rather than conserve — at times of system peak(s) than they would if they were to receive proper price signals.

Alternative Supplies — Purchases: Another increasingly important point about alternative supplies is that local power, when it is relatively expensive to generate, can be displaced with power generated by more efficient, distant sources. Similarly, excess cogenerated power can displace expensive utility generated power. However, such displacement requires "wheeling" which is the use of transmission facilities of one electric system to transmit power of and for others.

Market forces are developing tremendous industrial interest in wheeling. The reaction is similar to that experienced with contract carriage of natural gas.

The Era of Oversupply — The Next Ten Years

Contrary to what we see empirically, some people forecast that the United States will experience severe electricity shortages and brownouts by the early 1990s.

Electricity is the lifeblood of industry. Its members' need for adequate and reliable supplies has led ELCON to analyze very carefully future projections of demand and generating capabilities — both on a national and a regional basis.[4] We found that the electric utility industry at present is awash with capacity. Utilities report a national reserve margin of 33.9 per cent today. Utilities themselves say that this margin will exceed 25 per cent by 1994.

At first blush, these data do not appear to support assertions that a crisis is imminent. We thought that those predicting a crisis may be basing their concerns on certain regions, rather than on the nation as a whole. So we analyzed the utility data by the North American Electric Reliability Council regions. We found all but two regional projections in excess of 20 per cent in 1994. Those two (Electric Reliability Council of Texas and Mid-Continent Area Power Pool) were 19.1 per cent and 13.3 per cent, respectively — hardly a "crisis" situation.

Still concerned, we tested the utility projections' sensitivity to changed assumptions. We compared 11 alternative hypothetical scenarios with the utility projections (base case). Our conclusions from this sensitivity test are as follows: They find neither national nor regional reserve problems if utility projections are realized. Projections of future adequacy are sensitive to changes in assumptions regarding load growth. Potential regional problems appear in certain scenarios, but, the locations of the potential problems differ by scenario.

Our analysis, as is often the case, focused on the negative rather than the positive. We looked for problems, thus drawing attention away from opportunities. Specifically, we look at those areas that might have inadequate future reserves under alternative hypothetical scenarios. We did not discuss areas that will have more-than-adequate reserves. Neither did we explore possible market reactions to such conditions.

Specifically, we pointed out that utility projections show only two regions with reserve margins less than 20 per cent in 1994. We did not emphasize that:

- These utility forecasts show one region with reserves in excess of 30 per cent in 1994. Six other regions have reserves in excess of 20 per cent.
- One region would have 1994 reserves in excess of 40 per cent if cogeneration and alternative energy resource growth is robust. Three additional regions would have margins in excess of 30 per cent under such conditions.
- One region would have a 46 per cent margin in 1994 if successful plant life extension programs complement robust cogeneration and alternate energy resource development. Under such conditions, six of the nine regions would have reserves in excess of 30 per cent in 1994!

Marketplace Reactions

These data thus indicate that surplus generating capacity will exist in certain areas throughout the next decade. There is nothing peculiar about this finding. Indeed, pockets of excess production capacity exist from time to time in many industries other than the electric utility industry.

But marketplace reactions to excess capacity historically differ from regulated to unregulated industries. In unregulated industries, excess capacity usually puts *downward* pressure on the prices of most goods. In the electric utility industry excess capacity often results in *rising* prices. Indeed, price increases may be significant when the surplus is created by the completion of a large, new generating station and traditional accounting methods that front-load cost recovery are employed.

There are signs that changes involving both the level and the timing of cost recovery are on the horizon. Regulators are scrutinizing carefully the prudency question. Proposed new cost recovery methods being considered and adopted range from simple phase-in procedures — with and without capitalization provisions — to disallowance of rate basing of excess capacity.

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[3] Cogeneration potentials are not limited to industrials. For example, a McDonald's restaurant in San Diego last year installed a 65-kilowatt cogeneration unit designed to meet most of the electric, heating, and cooling needs of the 3,000-square foot facility. More recently, a California firm has introduced a 6.8-kilowatt unit designed for laundries, hotels, retirement homes, restaurants, and the like. This unit is only 3.5 feet high, 3.5 feet wide, and five feet long, and it has a 55 per cent thermal efficiency — about the same as most commercial hot water heaters. Obviously, commercial customers react to market forces as do industrial customers.

[4] This analysis is described in detail in our statement on "When Will the Lights Go Out?" Committee on Energy and National Resources, United States Senate, July 25, 1985.

These are predictable marketplace reactions to surplus conditions of an industry — but they are only the beginning. Continued existence of pockets of surplus generating capacity, in my view, ultimately will drive the owners to seek markets for this power. The "haves" will try to sell to the "have nots." Barriers to the movement of power — whether real or institutional — will be identified and dissipated.

Regulators are responding to these inevitable market forces in various ways. Some are trying hard to explore options, gather facts, and develop compromises that will benefit utilities and consumers alike. (Others appear to be taking the "ostrich" approach — wait long enough and everything will be fine.) Texas and Florida have held hearings, proposed rules, and even ordered actions regarding the movement of cogenerated power from utilities that argue that they do not need capacity to utilities that do. Illinois has actively studied proposals such as centralized dispatch, auction markets, unbundling of rates, and off-system sales. Illinois recognizes that there are potential problems that must be carefully studied before proceeding too far or too rapidly. However, its commissioners also recognize the important role that state public utility commissions can play in shaping the future. Pennsylvania ruled that ratepayers should not be required to pay for capacity deemed excess although revenues generated by the sale of electricity from excess capacity was not subject to regulation. And New York is investigating real-time spot pricing.

This list is far from complete. I do not mean to imply that the actions of these states necessarily are correct. The point that I would like to emphasize is simply that attempts to gather facts and understand the marketplace will provide an understanding and a recognition of the players that will produce positive results.

The Expected Industrial Reaction

In my view, industrials will continue to react to market forces in several logical ways. First, they will continue to advocate rates based on costs — both in traditional as well as in new ways. They will argue that proposals that assign a disproportionate cost responsibility to the industrial class are inappropriate and counterproductive. While not a new argument, it may gain more attention as industrial facilities are shut down and jobs in the community are lost, perhaps forever.

Plant shutdowns are very real. Testimony of one of the ELCON member companies before the California Public Utilities Commission highlights this point:

> Why my regrets? Starting from the early 1970s (my company) found its California-based energy-intensive operations becoming unprofitable. These were high-load factor plants where the cost of electricity was of the order of 10 per cent of manufacturing costs and all purchased energy costs could exceed 25 per cent. We were forced to close plants. During this period (my company) closed seven plants of its 13 manufacturing facilities located in California. The plants that remain operational, that are energy intensive, survive only because economics permitted us to employ cogeneration. As substantiation of the abrupt change in the nature of our operations, the electricity currently purchased at our six remaining plants is less than 15 per cent of our peak usage when we operated 13 in the seventies . . . I'm sure the more than 700 union employees, who lost their jobs when these plants closed, share my regrets . . .

Setting rates based on costs is important because for years industrials have been required to subsidize other customer classes. We believe that rates should be set so that when appropriate cost allocation methods are utilized, the rates of return for all customer classes are levelized. By definition, if the rate of return for one customer class exceeds the overall system rate of return — as is the case for the industrial class for most utilities — that class is required to subsidize other customers.

We know that the existing industrial cross-class subsidy is substantial. But measuring this subsidy is difficult. To try, we recently asked three consultants to provide us hard data on existing rates. They provided us data showing the revenue requirement and rate of return for the industrial class and total system in 84 cases. The consultants then calculated the amount that the industrial revenue requirements would have to be lowered to make the industrial rate of return just equal the overall system average. The results of these calculations show that industrials are subsidizing other customer classes to the whopping sum of $1.3 billion annually in those 84 cases alone. The subsidy for the U. S. is in excess of $2.5 billion per year. Eliminating this subsidy by setting rates based on costs would substantially help industrial firms that are suffering from intense domestic and foreign competition.

Additionally, however, we should rethink the way costs are recovered. Industrials, knowing well how the market reacts to overcapacity in their industries, may suggest methods that (1) reduce the front-end loading and (2) change the timing of capital cost recovery. Such methods can send price signals to consumers that comport more closely with market forces and simultaneously keep utilities financially stable and healthy.

Second, industrials may advocate more flexibility in determining terms and conditions of the contracts they negotiate with utilities both in the buying and selling of power. Clearly, a utility should neither sell power for less than its variable production costs nor buy power at more than its true avoided costs. However, rigid institutional and regulatory procedures should not preclude the consummation of business arrangements that benefit all.

Some exciting ideas are being discussed and, in some instances, tested. They should be encouraged where they are demonstrated to be beneficial. For example, utilities are negotiating interruptible contracts that give the customer the option of being interrupted or paying the price of power purchased off the grid plus a percentage markup. Some commissions are ordering utilities to wheel cogenerated power to other utilities when they do not need the capacity. Some utilities are even testing hourly sales of power at "spot market" prices. Utilities, regulators, and customers must be encouraged to explore options, subject to strict protective guidelines, rather than stick to tradition for tradition's sake.

Third, industrials must — and will — continue to try to lower the costs of the goods they produce. This will drive them to seek, among other things, lower-cost power from distant sources when it is available.

Electricity is the lifeblood of American industry. These firms must have adequate and reliable electricity — but they must be able to purchase it and remain competitive. While industry does not view wheeling as a replacement for native generating capacity, it sees potentials for additional movements of power that can benefit all.

For example, power from efficient but excess capacity can be moved to areas with less efficient generation or to areas with demonstrated capacity needs. Wheeling to an industrial that otherwise must shut down may benefit — rather than harm — the host utility. Power from a cogenerator can be wheeled to distant utilities that need capacity by a host utility that does not. Indeed, excess cogenerated power can be used to displace purchased power priced artificially high by inappropriate rate-making procedures without "harming" other customers in a real sense.

With the real-life constraints of the electrical transmission grid clearly in mind, ELCON has developed a procedure that we believe will allow — indeed encourage — the development of additional transmission while protecting consumers and utilities alike.

We are not advocating an opening of the grid to any and all to shop around for cheap power. Rather, we advocate a policy that simply would allow users, including cogenerators, to apply for wheeling orders. The appropriate regulatory authority would then adjudicate all aspects of the request, balancing fairly the interests of all customers served by the utility. Wheeling rates should be based on cost of service and should take into account the firmness, voltage, the distance the power is moved, and the actual equipment used by the utility for the transaction.[3]

There are many differences between the movement of gas and electricity, but there are many similarities. The same industrial managers that have suffered, and learned, from the movement of gas are ready to try limited experiments in the electricity arena. They realize that they must be ready to give up if they are to receive. They also realize that it is a very sophisticated market that takes tremendous expertise and communication.

Industrial users of electricity believe that all can benefit if innovative and creative utility managers, regulators, and consumers work together. But they believe that the market will prevail, even if individual utilities try to stonewall. The price is too great.

EDITOR'S NOTE: The foregoing article was adapted from a presentation by the author at the 97th annual convention and regulatory symposium of the National Association of Regulatory Utility Commissioners in November, 1985.

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[3] Our views on wheeling are set forth in detail in the ELCON filing, "Regulation of Electricity Sales-for-Resale and Transmission Services," FERC, Docket No. RM85-17-000, Phase 1, August 9, 1985.

Utility Installs Hot Line to Report Energy Theft

Northern Indiana Public Service Company is implementing a telephone hot line which customers may use to report known or suspected meter tampering or energy theft. "Energy theft is a dangerous crime that can result in electrical shock, electrocution, or fire," says Hermen Kerr, acting director of security at the Indiana utility. "The person who tampers with meters or gas lines puts many innocent people in jeopardy, and in addition is really robbing us all as ultimately losses are passed on to paying customers through higher prices." The company is asking residents of its service area who know or suspect cases of meter tampering, theft, or unlawful reconnection of utility service, to report it in confidence by calling a 24-hour, toll-free telephone number.

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PROFILES IN ELECTRICITY [illegible]

Cost-of-Service Survey

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BACKGROUND

Cost-of-service studies determine the total costs incurred by a utility in providing service to its customers and the allocation of those costs to customer classes. Revenue collected from each customer class then may be compared with that class' cost responsibility to determine the extent to which each class is reimbursing the utility for the costs it incurred in providing service.

Many of the costs incurred by a utility are "joint" costs, incurred on behalf of all customers rather than for a specific customer class. As a result, the allocation of a utility's costs requires engineering, economic and accounting expertise, as well as a significant amount of informed judgment. Several appropriate cost-of-service methodologies have been developed for this process.

The particular method selected depends upon such factors as the diversity of the system load, the types and sizes of customers and customer classes and the type, time and rate of usage. A proper cost-of-service method will allocate each category of costs to the responsible customer class. Appropriately designed electric rates then will recover these costs (including a fair return on investment) from each class. A proper cost-of-service based rate design will produce approximately equal rates of return on investment from each of the utility's customer classes. That is, the cost burden will be equitably shared among all of the utility's customers.

There are three general categories of cost-of-service study methodologies: demand methods, consumption methods and load curve methods. These methods differ mainly in their allocation of fixed costs among the various customer classes.

Fixed costs generally are demand-related. A utility builds generating units and transmission lines based upon the maximum requirement expected to be imposed on its system at any point in time. Thus, the fixed costs of this equipment are incurred to meet the peak load(s) of the system. A proper cost-of-service methodology allocates these costs to each customer class in proportion to that class' contribution to the system peak(s) (or maximum demands).

Other costs are "customer-related" costs -- mainly meter reading and billing costs. These are related to the number of customers on the system. Still other costs are "energy related" -- mainly fuel costs -- which are related to electricity (KWH) consumption.

Some equipment is used only to serve particular customer classes. For example, the distribution network provides service to residential and small commercial customers at low voltage levels. The costs of this equipment should be borne only by those who use it.

The revenue burden is being equitably shared when each customer class produces roughly the same rate of return to the utility. On the other hand, there is a strong indication that the customers of a class are being overcharged (or undercharged) if a cost-of-service study shows that a particular customer class is producing a rate of return significantly above (or below) the utility's average system rate of return.

PREVIOUS RESEARCH

ELCON commissioned surveys of cost-of-service studies in 1977, 1978, and 1982. The results of these surveys indicate that industrial electricity users pay more than their fair share of utilities' costs of service.

These surveys show that in the vast majority of instances, the industrial rate of return exceeds both the residential and the total system rate of return. Specifically, this earlier research demonstrated that the industrial rate of return exceeded the residential rate of return in 588 -- or 84 percent of the 701 studies included in the 1982 survey.[1] The industrial rate of return exceeded the system average rate of return in 526 of the studies. Alternatively, the residential rate of return was less than the system average rate of return in 610 -- or 87 percent -- of the studies.

CURRENT RESEARCH

The current survey encompasses 84 cost-of-service studies for 73 electric utilities operating in 32 states (several utilities operate in more than one state). The studies include actual and forecasted test periods for 1979 through 1986 and reflect a variety of cost allocation methodologies. The results of the survey are provided in Appendix Table A-1 at the end of this Profile. This table is essentially the same as those contained in previous ELCON cost-of-service profiles.

Three independent utility rate consultants provided cost-of-service information for this survey: Drazen-Brubaker & Associates, Inc., St. Louis, Missouri; Kennedy and Associates, Inc., Atlanta, Georgia; and Cook, Eisdorfer, Willer & Associates, Inc., St. Louis, Missouri.

Data are from electric utility cost-of-service studies on file with each of the consultants. In each case, the cost-of-service study provided is the most recent available for the utility included in the survey. Thus, unlike earlier ELCON surveys, only one cost-of-service study is provided for each utility.

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[1] Cost of Service Survey, Profiles in Electricity Issues, No. 6, Electricity Consumers Resource Council, Washington, D.C., May 1982.

The data compare after-tax rates of return for residential and industrial service with the system average rate of return. Various cost-of-service methodologies are represented in the data provided.

For each utility, that methodology determined by the particular consultant to be most appropriate is included, considering the electric load, usage and other customer characteristics of that utility. The consultant calculates the rate of return (in percent) for the industrial and residential customer classes and the system average rate of return for each utility.

In 1984 (the latest year for which sales figures are availble), the utilities included in the survey had total kilowatt-hour (KWH) sales of 1,320 billion KWH, or approximately 57.9 percent of total energy sales for the U.S. electric utility industry. Total industrial sales for these utilities was 448.9 billion KWH or about 53.6 percent of total U.S. industrial electricity sales in 1984.

Survey results show that the industrial rate of return exceeds the residential rate of return in 79 -- or 94 percent -- of the 84 cost-of-service studies contained in the survey. In 76 cost-of-service studies -- or 90 percent of the total -- the industrial rate of return exceeds both the residential and the system average rates of return.

This survey clearly shows that industrial customers usually are required to pay more for electricity, relative to the cost of producing service, than do residential customers.

Contrary to popular misconception, industrials generally are required to subsidize other electricity consumers; industrial users are _not_ being subsidized by residential customers.

MAGNITUDE OF THE SUBSIDY

How significant is the subsidy that industrial electricity users pay to other electricity customers? This survey determines the dollar subsidy paid by industrial consumers in each cost-of-service study by determining the revenue that must be deducted from the industrial class' revenue requirement to equilibrate the rate of return on investment from that class with the system average rate of return. This information is contained in Table 1.

For the 73 utilities included in the survey, Table 1 shows that the industrial subsidy totals $1.37 billion in 1984 dollars. For industrial users, this represents approximately 3.1 mills (or more than 3 tenths of a cent) for each KWH of electricity purchased in 1984. Based on total industrial sales for the U.S. electric utility

TABLE 1

INDUSTRIAL SUBSIDY TO OTHER RATE PAYERS

STATE	KWH (000) RESIDENTIAL	KWH (000) INDUSTRIAL	KWH (000) SYSTEM	TOTAL SUBSIDY 1984 $ (000)	INDUSTRIAL SUBSIDY (cents/kwh)
ALABAMA	9,174,780	14,651,012	32,000,704	$65,442	0.45
ARKANSAS	5,682,151	6,803,579	18,741,268	$17,881	0.26
CALIFORNIA	37,850,821	35,882,149	116,653,298	$248,268	0.69
CONNECTICUT	6,232,209	7,168,737	15,365,884	$46,262	0.65
DELAWARE	1,460,922	2,104,925	5,127,948	$3,722	0.18
FLORIDA	41,674,215	11,416,160	85,621,265	$27,851	0.24
GEORGIA	12,004,092	19,970,447	43,458,560	$55,900	0.28
ILLINOIS	27,218,115	22,290,253	93,472,067	$138,844	0.62
INDIANA	16,090,650	20,990,692	52,751,276	$34,238	0.16
KANSAS	4,134,241	4,297,350	12,604,433	$10,750	0.25
KENTUCKY	2,513,602	2,234,226	7,900,847	$13,258	0.59
LOUISIANA	12,551,836	21,854,533	43,687,789	$60,757	0.28
MAINE	2,358,416	1,892,432	5,896,465	$4,545	0.24
MARYLAND	6,564,194	6,248,537	18,290,683	$2,951	0.05
MASSACHUSETTS	1,124,206	1,030,982	3,265,866	$2,085	0.20
MICHIGAN	21,192,753	30,743,001	68,110,463	$142,219	0.46
MINNESOTA	5,917,702	16,969,311	25,392,683	$54,702	0.32
MISSOURI	10,836,757	8,164,226	29,778,512	$23,121	0.28
NEW JERSEY	13,349,873	10,259,035	46,599,606	$37,105	0.36
NEW MEXICO	1,517,939	1,054,474	4,719,063	$9,926	0.94
NEW YORK	13,750,831	16,603,651	46,315,469	$28,277	0.17
NORTH CAROLINA	19,026,862	20,501,980	55,795,684	$48,572	0.24
OHIO	26,756,003	33,651,166	82,854,890	$39,272	0.12
OKLAHOMA	5,927,792	8,319,885	16,627,887	$18,952	0.23
PENNSYLVANIA	27,802,962	30,170,276	88,541,407	$89,747	0.30
SOUTH CAROLINA	9,488,599	15,929,841	32,458,812	$29,079	0.18
TEXAS	47,544,960	36,644,078	163,072,149	$38,968	0.11
UTAH	2,716,432	3,853,949	9,375,216	$12,474	0.32
VIRGINIA	19,314,868	16,079,866	43,189,440	$44,209	0.27
WEST VIRGINIA	6,161,538	7,782,854	19,570,354	$11,383	0.15
WISCONSIN	8,304,584	9,843,686	27,317,694	$8,779	0.09
WYOMING	760,779	3,557,828	5,710,591	$3,790	0.11
TOTAL	427,005,684	448,965,121	1,320,268,273	$1,373,329	0.31
ELECTRIC ENERGY SALES-1984	777,421,000	837,661,000	2,279,923,000		
RATIO UTILITY/ TOTAL SALES	0.549	0.536	0.579		

industry in 1984 -- 837.7 billion KWH -- this amounts to a total industrial subsidy of $2.6 billion. Alternatively, industrial KWH sales for the utilities included in this survey account for 53.6 percent of total industrial KWH sales for 1984. If extrapolated to represent 100 percent of 1984 sales, the industrial subsidy to other customer classes would total approximately $2.56 billion.

SUMMARY AND CONCLUSIONS

This survey of cost-of-service studies updates earlier studies commissioned by ELCON and quantifies the extent to which industrials subsidize other electricity users.

Survey results show that in 79 -- or 94 percent -- of the 84 cost-of-service studies, the industrial class rate of return on investment exceeds that of the residential class. In 76 cost-of-service studies, the industrial rate of return also exceeds the system average rate of return. Industrials, thus, generally are required to subsidize other electric utility customers.

This profile also quantifies the subsidy paid by industrials to other electricity users. For each of the 84 cost-of-service studies, electric rate consultants estimated the change in revenue requirement necessary to cause the industrial rate of return to equal the system average rate of return. In 1984 dollars, this annual subsidy amounts to $1.37 billion or more than 3 mills (3 tenths of a cent) for each KWH of industrial sales represented by those utilities included in the survey.

When extrapolated to represent 100 percent of 1984 industrial KWH sales, this subsidy totals approximately $2.5 billion. This subsidy is very substantial. It suggests that industrial rates are approximately 6 percent higher on average than they should be. $2.5 billion is roughly equal to the negative balance of trade with England or Italy. It is enough to pay the annual electric bills of more than 4 million homes -- nearly twice the number of residential customers in New York City.

Despite these facts, proposals continue to be advanced which would further undermine established cost-of-service ratemaking principles. These proposals threaten to produce additional distortions in electricity rates and to increase the burden borne by industrial users in subsidizing other classes of electricity users.

These proposals also undermine the competitiveness of U.S. firms in both domestic and foreign markets. Industrials cannot simply pass on increased electricity costs to their customers. This is particularly true when industrial electricity rates in other countries are subsidized or when, as is sometimes the case, industry is offered special long-term electricity discounts in exchange for building new facilities in foreign countries. This process leads to erosion of the U.S. industrial base, contributes to domestic unemployment and causes U.S. industry to reduce electricity purchases through such means as self-generation and cogeneration.

APPENDIX A

SUMMARY OF COST-OF-SERVICE STUDIES

APPENDIX TABLE A-1

SUMMARY OF COST-OF-SERVICE STUDIES

STATE	UTILITY	YEAR OF STUDY	COST-OF-SERVICE METHOD	RATE OF RETURN--%		
				RESIDENTIAL	INDUSTRIAL	SYSTEM
ALABAMA	ALABAMA PWR CO.	1981	FOUR CP	4.95	8.60	7.12
ARKANSAS	ARKANSAS PWR & LT	1984	SINGLE CP	8.71	10.92	9.64
	OKLAHOMA G & E	1983	A&E	7.77	6.63	7.31
	SOUTHWESTERN ELEC PWR	1983	SINGLE CP	6.52	9.56	7.61
CALIFORNIA	PACIFIC G & E	1984	TWELVE CP	0.24	12.04	5.34
	SAN DIEGO G & E	1986	TWELVE CP	5.29	23.86	11.57
	S. CALIFORNIA EDISON	1983	TWELVE CP	-0.06	4.34	2.23
CONNECTICUT	CONNECTICUT PWR & LT	1984	A&E	6.73	13.88	10.19
DELAWARE	DELMARVA PWR & LT	1983	FIVE CP	9.88	12.18	11.70
FLORIDA	FLORIDA PWR CORP	1984	WINTER/SUMMER CP	6.01	9.06	7.12
	FLORIDA PWR & LT	1984	WINTER/SUMMER CP	6.52	10.24	8.55
	GULF PWR CO	1984	THREE CP	6.53	9.25	7.70
	TAMPA ELEC CO	1984	WINTER/SUMMER CP	5.25	7.14	6.16
GEORGIA	GEORGIA PWR CO	1984	NEAR PEAK	3.16	10.91	8.40
ILLINOIS	CENTRAL ILLINOIS LT	1982	SINGLE CP	4.14	13.36	8.38
	CENTRAL ILL PUB SERV	1981	THREE CP	4.00	8.82	6.57
	COMMONWEALTH EDISON	1982	SINGLE CP	7.59	15.03	11.27
	ILLINOIS PWR CO	1983	SINGLE CP	4.43	16.58	9.18
	UNION ELEC CO	1983	THREE CP	-0.78	8.59	6.81
INDIANA	IND & MICH ELEC CO	1984	TWELVE CP	7.94	6.69	7.86
	INDIANAPOLIS PWR & LT	1981	TWELVE CP	6.98	9.57	8.30
	NORTH INDIANA PUB SERV	1982	TWO CP	2.80	6.24	4.45
	PUB SERV CO OF INDIANA	1984	TWELVE CP	10.69	11.44	11.25
	SOUTH INDIANA G & E	1979	FOUR CP	4.31	7.28	5.88
KANSAS	KANSAS G & E	1982	FOUR CP	7.21	15.16	9.69
	KANSAS PWR & LT	1980	THREE CP	4.50	6.12	5.73
KENTUCKY	LOUISVILLE G & E	1982	SINGLE CP	4.34	11.11	7.65
LOUISIANA	GULF STATES UTIL	1982	4 CP/ A&E	7.24	10.72	9.23
	LOUISIANA PWR & LT	1984	FOUR CP	2.33	6.95	4.51
	NEW ORLEANS PUB SERV	1983	FOUR CP	-4.99	13.87	3.69
MAINE	CENTRAL MAINE PWR CO	1979	NEAR PEAK	8.36	12.36	11.00
MARYLAND	BALTIMORE G & E	1983	SINGLE CP	7.53	9.59	9.37
MASSACHUSETTS	WESTERN MASS ELEC	1983	A&E	10.02	11.31	9.71
MICHIGAN	CONSUMERS PWR CO	1985	TWELVE CP	7.70	10.92	9.82
	DETROIT EDISON	1985	SINGLE CP	1.87	5.50	3.97
	IND & MICH ELEC CO	1985	TWELVE CP	5.79	6.50	6.76
MINNESOTA	MINNESOTA PWR & LT	1981	A&E	1.31	7.67	5.50
	NORTHERN STATES PWR	1981	SINGLE CP	6.14	9.08	7.89
MISSOURI	ARKANSAS PWR & LT	1984	SINGLE CP	9.78	11.77	10.58
	EMPIRE DISTRICT ELEC	1981	SINGLE CP	6.04	23.22	10.25
	KANSAS CITY PWR & LT	1984	NEAR PEAK	1.69	5.81	4.71
	UNION ELEC CO	1984	TWO CP	2.00	4.66	3.44

APPENDIX TABLE A-1

SUMMARY OF COST-OF-SERVICE STUDIES

STATE	UTILITY	YEAR OF STUDY	COST-OF-SERVICE METHOD	RATE OF RETURN--% RESIDENTIAL	INDUSTRIAL	SYSTEM
NEW JERSEY	JERSEY CENTRAL PWR & LT	1984	FOUR CP	7.99	14.14	10.06
	PUB SERV ELEC & GAS	1981	SINGLE CP	8.45	12.03	10.77
NEW MEXICO	PUB SERV CO OF N MEXICO	1984	TWELVE CP	6.27	15.29	10.65
	TEXAS-N MEXICO PWR CO	1982	THREE CP	7.89	14.59	9.48
NEW YORK	CENTRAL HUDSON G & E	1982	WINTER/SUMMER CP	6.90	14.89	10.98
	CONSOLIDATED EDISON	1981	SINGLE CP	11.43	12.05	11.56
	N Y STATE E & G CORP	1986	NEAR PEAK	9.24	10.07	10.06
	ORANGE & ROCKLAND	1983	SINGLE CP	9.28	12.16	11.01
NORTH CAROLINA	CAROLINA PWR & LT	1983	SINGLE CP	7.86	11.70	9.70
	DUKE PWR CO	1984	SINGLE CP	5.31	8.51	7.10
OHIO	CINCINNATI G & E	1984	TWO CP	6.16	14.36	10.55
	CLEVELAND ELEC ILLUM	1983	FOUR CP	14.05	15.13	14.55
	COLUMBUS & S OHIO ELEC	1983	SINGLE CP	7.49	9.97	9.83
	OHIO EDISON CO	1985	TWELVE CP	9.51	10.04	11.08
	OHIO PWR CO	1983	TWELVE CP	8.97	11.07	10.30
	TOLEDO EDISON CO	1983	TWELVE CP	9.36	8.52 *	9.29
OKLAHOMA	OKLAHOMA G & E	1984	SINGLE CP	5.59	9.69	7.87
PENNSYLVANIA	DUQUESNE LT CO	1984	SINGLE CP	12.22	13.79	11.19
	PENN ELEC CO	1985	TWO CP	6.29	9.12	7.80
	PENN PWR & LT	1985	TWO CP	7.33	10.97	8.92
	PHILADELPHIA ELEC	1784	FOUR CP	5.87	11.67	9.70
	WEST PENN PWR CO	1984	SINGLE CP	8.02	8.72	8.87
SOUTH CAROLINA	CAROLINA PWR & LT	1983	SINGLE CP	7.19	12.45	10.09
	DUKE PWR CO	1984	SINGLE CP	4.41	9.33	6.88
	S CAROLINA E & G	1983	SINGLE CP	8.70	8.14	8.71
TEXAS	CENTRAL PWR & LT CO	1981	FOUR CP	5.57	11.20	8.59
	EL PASO ELEC CO	1983	FOUR CP	8.64	10.30	9.58
	GULF STATES UTIL	1983	FOUR CP	7.31	8.35	8.03
	HOUSTON LTG & PWR	1984	NEAR PEAK	9.51	11.55	10.46
	SOUTHWESTERN ELEC PWR	1983	FOUR CP	8.47	11.00	10.22
	TEXAS-N MEXICO PWR CO	1983	FOUR CP	8.18	25.82	10.16
	TEXAS UTILITIES ELEC	1983	A&E	12.50	13.52	12.46
UTAH	UTAH PWR & LT	1982	FIVE CP	9.55	13.56	11.93
VIRGINIA	APPALACHIAN PWR CO	1982	TWELVE CP	8.65	9.77	9.41
	VIRGINIA PWR CO	1984	A&E	9.02	12.78	10.76
WEST VIRGINIA	APPALACHAIN PWR CO	1983	TWELVE CP	5.85	8.48	7.41
	MONONGAHELA PWR CO	1984	SINGLE CP	8.13	11.58	10.11
WISCONSIN	WISCONSIN ELEC PWR CO	1986	TWELVE CP	9.23	11.30	10.53
	WISCONSIN PWR & LT CO	1986	TWELVE CP	9.37	6.56	8.55
	WISCONSIN PUB SERV CORP	1986	TWELVE CP	5.76	13.97	9.69
WYOMING	PACIFIC PWR & LT	1983	SINGLE CP	7.45	10.20	9.43
	UTAH PWR & LT	1983	EIGHT CP	5.33	9.47	8.49

NOTES TO TABLES

1. Information included in tables 1 and A-1 was provided from cost-of- service studies on file with utility rate consultants.

2. Cost- of- service methods presented are those recommended by the rate consultants as most appropriate for the particular utility and test year being considered. These include:

   Four CP -- four coincident peaks
   Single CP -- maximum annual coincident peak
   A&E -- average and excess
   Twelve CP -- twelve coincident peaks
   Five CP -- five coincident peaks
   Winter/Summer CP -- winter and summer seasonal coincident peaks
   Near Peak -- system peak demands within a certain % of the annual system peak (e.g., 90% of peak) are used to allocate costs.
   Three CP -- three coincident peaks
   Two CP -- two coincident peaks
   4 CP/ A&E -- combination of four coincident peaks and average and excess methods
   Eignt CP -- eight coincident peaks

3. Killowatt-hour sales for each state are those provided by the cost- of- service studies for those utilities included in the survey.

4. Electric Energy Sales--1984 are totel KWH sales for the U.S. electric utility industry for 1984 as determined by the Edison Electric Institute.

5. Industrial Subsidy is that amount of revenue necessary to be deducted from the industrial class revenue requirement to cause the rate of return for that class -- as determined by the cost-of- service study for the test year under consideration -- to equal the system average rate of return. Figures are in 1984 dollars.

6. Industrial Subsidy per KWH is derived by dividing the industrial subsidy in 1984 dollars by each state's industrial KWH sales for those utilities included in the survey.

INDUSTRIAL COGENERATION: A Background Paper

JUNE 1983

ELCON

ELECTRICITY CONSUMERS RESOURCE COUNCIL

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INDUSTRIAL COGENERATION:
A BACKGROUND PAPER

JUNE 1983

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FOREWORD

Cogeneration is a process that produces both electrical or mechanical power and useful thermal heat from one fuel source. Cogeneration is not new; indeed, industrial firms have cogenerated for nearly a century. Recently, however, cogeneration has received increased attention as a means to meet future electricity needs and reduce our nation's dependence on imported oil.

This paper describes how cogeneration works, why it is efficient, and existing legislated incentives intended to spur the development of cogeneration facilities. It was prepared by an ELCON member company working group headed by John Anderson, ELCON Senior Economist.

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APPENDIX

State-by-State Report on the Implementation of Section 210 of PURPA

I. INTRODUCTION

Cogeneration is defined as the sequential production of electrical or mechanical power and useful thermal heat from the same fuel source.

In the generation of electricity, cogeneration utilizes fuel more efficiently than conventional generation by recovering energy that otherwise would be wasted. When used appropriately, cogeneration may recover more than twice the amount of useful energy out of the fuel used when compared to conventional electric utility generation.

Cogeneration is not new, but it has recently become a fashionable way to describe an old process. Good data do not exist to measure accurately the magnitude of either past or present cogeneration; however, a few figures help to put cogeneration into proper perspective.

At the turn of the 20th century, industrial firms produced nearly 60 percent of the nation's electricity — 3.5 billion kilowatt-hours (kwh) of a total of 6.0 billion kwh.*/ Much of this early generation was in the form of cogeneration. Often, these early facilities were built in remote areas, such as logging and mining camps, and were not connected to electric utilities in any way.

Industrial generation reached an all-time high in 1969 when industrial firms generated 111 billion kwh. However, by this year the generation of electricity by utilities had grown to 1,442 billion kwh, thus reducing the industrial's share of the total to seven percent. Since 1969, both the absolute quantity and the relative share of industrial generation has fallen. Indeed, in 1981 industrials generated only 64.4 billion kwh, or less than three percent, of the 2,359 billion kwh generated that year.

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*/ The data representing electricity generation were obtained from various editions of the Statistical Yearbook, Edison Electric Institute, Washington, D.C.

The share of electricity generated by industrials fell as central station generation became more economically attractive. As modern, integrated electrical systems were developed, utilities were able to produce electricity more reliably and economically. For example, in 1926 utilities on the average spent 2.7 cents per kwh to generate electricity, but only 1.54 cents per kwh in 1968.

Today, industrial firms are showing a renewed interest in cogeneration, primarily due to a reversal in this historical economic trend. Since the early 1970's, many factors -- including rising fuel prices, lengthy construction periods, high interest rates, increased regulatory costs, etc. — have combined to increase the cost of electricity purchased from utilities. Under certain conditions, this renewed interest has resulted in corporate decisions to invest in cogeneration facilities. Under other conditions, industrial firms have determined that their electricity needs are more efficiently met by purchased power.

This paper first describes cogeneration and discusses how cogeneration results in a more efficient use of the primary fuel source. Major obstacles and certain legislated incentives to industrial cogeneration are then explored.

The paper is limited to discussions of industrial-owned cogeneration facilities, although many of the incentives described herein apply also to small power production and other than industrial-owned cogeneration facilities.

II. WHY IS COGENERATION EFFICIENT?

Efficiency in the generation of electricity is measured by the "heat rate" — the amount of fuel required (usually in British thermal units — Btu's) — to generate 1 kwh of electricity. The lower the heat rate, the greater the efficiency of the process. When used appropriately, cogeneration may recover more than twice the amount of useful energy out of the fuel used when compared to conventional electric utility generation.

Conventionally, electric utilities use approximately 10,000 Btu's of heat to generate one kilowatt-hour (kwh) of electricity.*/ Since a kilowatt-hour of electricity will produce only 3,412 Btu's, the calculated thermal efficiency of conventional electric utility facilities is about 34 percent.

Cogeneration integrates the electricity generating process and the thermal energy requirements of industrial manufacturing processes. This integration allows the recovery of some of the energy that would be exhausted into the atmosphere in conventional electric utility generation facilities. If cogeneration is practiced, the energy needed to generate that one kilowatt-hour of electricity can be appreciably less, depending on the system used. Cogeneration system efficiencies can be higher than 75 percent.

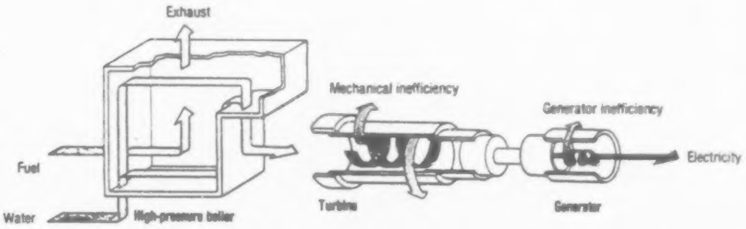
In a conventional electric utility thermal generation facility, water is converted into high-pressure, superheated steam in a boiler. Utilities use steam at high pressure (600-2,000 pounds per square inch [psi] or higher) and frequently at temperatures in excess of 1,000 degrees F. This steam is allowed to expand in a steam turbine, transferring some of its energy to the turbine shaft which, in turn, drives an electrical generator. The steam, now at a lower pressure and temperature, flows into a condenser where the remaining energy (heat) is exhausted into the atmosphere as it condenses to water again. The steam is converted to water so that it can be pumped back into the boiler and the cycle repeated.

---

*/ The U.S. Department of Energy reports that the prevailing heat rate factors at fossil fuel steam electric power plants in the U.S. was 10,353 Btu/kwh over the 1979-1982 time period. Monthly Energy Review, U.S. DOE/Energy Information Administration, Washington, D.C., October 1982, "Conversion Factors."

Figure 2.1 illustrates the conventional electric utility thermal generating process. For reference purposes, electric utilities account for about 29 percent of our nation's primary energy use, mainly through the combustion of fuels in central power stations.

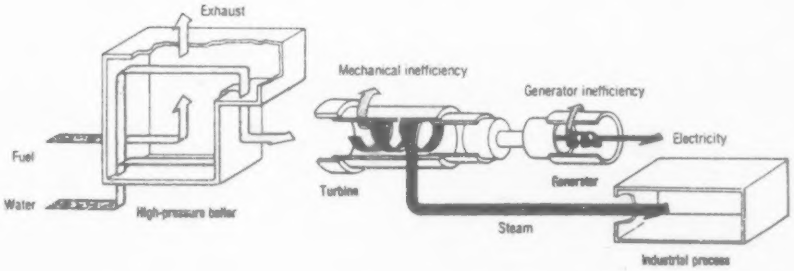
FIGURE 2.1



Industrial firms often require thermal energy in their manufacturing process. For example, steam is used for heating, drying, evaporating, etc. The steam needs of industry vary widely, but usually industrial processes require relatively low-pressure, low-temperature steam (frequently in the neighborhood of 150 psi, 365 degrees F). These steam needs often can be provided by cogeneration facilities.

There are many different cogeneration configurations, depending upon the steam and electricity needs of the particular industrial process. Several of the more common types are described in the next section of this paper. One type of cogeneration system -- the one that is most closely related to ordinary generation -- is discussed here to illustrate how the fuel is used more efficiently than in conventional generation. Figure 2.2 illustrates this cogeneration system.

FIGURE 2.2


Exhaust
Mechanical inefficiency
Generator inefficiency
Electricity
Fuel
Water
High-pressure boiler
Turbine
Generator
Steam
Industrial process

In this illustrative cogeneration system (which is an expansion of a utility generation system), high-pressure, high-temperature steam is produced in a boiler and used to turn a turbine for the generation of electricity — similar to a utility generation system. In this case, however, the lower-pressure, lower-temperature exhaust steam is then used to do useful work. In plants that produce chlorine and caustic soda, low pressure (or process) steam is used to evaporate water from dilute caustic soda, making the caustic soda into a salable product. In refineries, process steam is used to distill crude oil, separating it into gasoline, distilate, oils, and residual oil. Paper companies use process steam to dry wood pulp in the production of paper.

A Comparison of Generation and Cogeneration Efficiencies

Only a relatively small proportion of the total heat content of superheated steam is transferred to the turbine in a conventional electrical generation system. As an example, a boiler may put 1,300 Btu/lb of energy into superheated steam. Only about 450 Btu/lb is transferred to the turbine for conversion into electricity by the generator. The remaining 850 Btu/lb is wasted as the steam is transported from the turbine and is turned back into water in a condenser. In this illustration, only approximately 35 percent of the usable energy is used (450 out of 1,300 Btu/lb), while 65 percent of the energy is wasted. It warms up the cooling water and is rejected into a river, a lake or the atmosphere.

In a cogeneration system configured such as that illustrated in Figure 2.2, a smaller proportion of the pressure and temperature-energy of the steam is utilized by the turbine than in a conventional generation system. Thus, proportionally less electricity is produced. However, both pressure- and temperature-energy are captured from the reject steam and used in an industrial process. In such applications, the energy given up by the steam as it condenses serves a useful purpose rather than being wasted.

Figure 2.3 illustrates a typical industrial operation that requires 250,000 lb/hr of process steam which is produced in a low-pressure boiler. In an hour this operation also purchases 10,000 kwh of electricity from a utility, which makes the power by ordinary generation. The total fuel heating value required for producing the process steam and the electricity is 470 million Btu/hr.

As seen in Figure 2.4 the same amounts of process steam and electricity can be made, through cogeneration, by using only 410 million Btu/hr of fuel — a savings of 60 million Btu/hr, or 13%. Assuming a fuel cost of $4.00 per million Btu, the savings would be more than $2 million/year. The utility does not have to purchase the fuel required to make the 10,000 kwh. The industrial firm buys more fuel, but doesn't have to purchase the electricity. The net savings to the industrial firm is the savings on electricity less the extra cost of fuel. Overall, 86,000 barrels of oil equivalent per year are saved in this example.

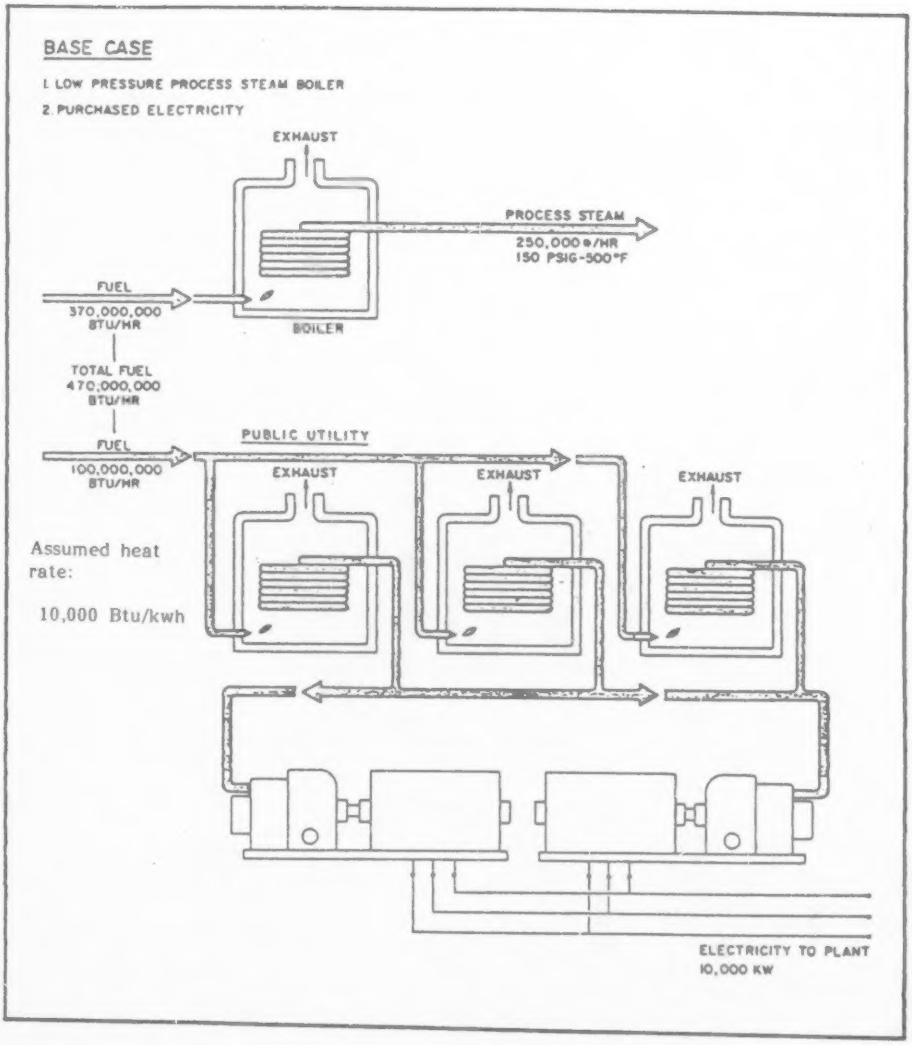
Table 2.1 compares the efficiencies of conventional electrical generation and process steam facilities with one type of a steam turbine cogeneration facility, using the assumed performance characteristics contained in Figures 2.3 and 2.4.

TABLE 2.1

SUMMARY OF EFFICIENCIES

	Conventional Electrical Generation and Industrial Process Steam Facilities:		Steam Turbine Topping Cycle Cogeneration:	
Output	**Quantity**	**Fuel Consumed**	**Quantity**	**Fuel Consumed**
Process Steam	250,000 #/hr 150 PSIG-500°F	370,000,000 Btu/hr	250,000 #hr 150 PSIG-500°F	370,000,000 Btu/hr
Electricity	10,000 kw	100,000,000 Btu/hr	10,000 kw	40,000,000 Btu/hr
Heat rate	$\frac{100{,}000{,}000 \text{ Btu/hr}}{10{,}000 \text{ kwh}}$ = 10,000 Btu/hr		$\frac{40{,}000{,}000 \text{ Btu/hr}}{10{,}000 \text{ kwh}}$ = 4,000 Btu/kwh	
Electrical Generation Efficiency:	$\frac{3{,}412 \text{ Btu/kwh}}{10{,}000 \text{ Btu/kwh}}$ = 34.1%		$\frac{3{,}412 \text{ Btu/kwh}}{4{,}000 \text{ Btu/kwh}}$ = 85.3%	

FIGURE 2.3

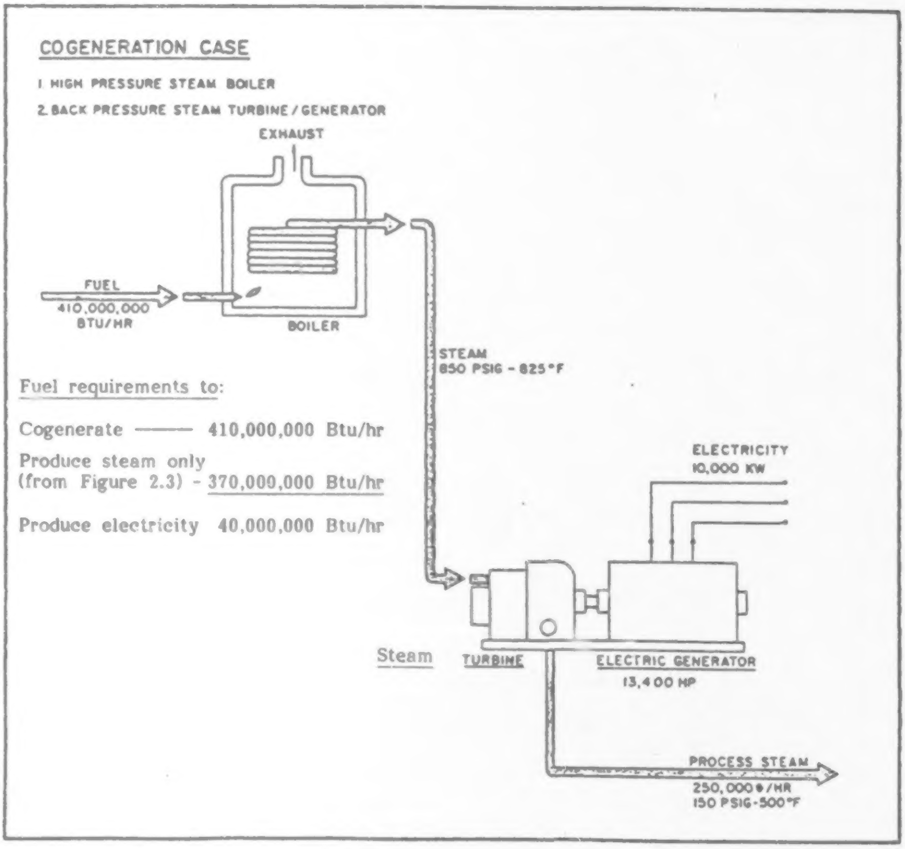

BASE CASE
1. LOW PRESSURE PROCESS STEAM BOILER
2. PURCHASED ELECTRICITY
EXHAUST
PROCESS STEAM
250,000 #/HR
150 PSIG-500°F
FUEL
370,000,000
BTU/HR
BOILER
TOTAL FUEL
470,000,000
BTU/HR
FUEL
100,000,000
BTU/HR
PUBLIC UTILITY
EXHAUST
EXHAUST
EXHAUST
ELECTRICITY TO PLANT
10,000 KW

Assumed heat rate:

10,000 Btu/kwh

Generation efficiency: $\frac{3{,}412 \text{ Btu/kwh}}{10{,}000 \text{ Btu/kwh}} = 34.12\%$

FIGURE 2.4


COGENERATION CASE
1. HIGH PRESSURE STEAM BOILER
2. BACK PRESSURE STEAM TURBINE / GENERATOR
EXHAUST
FUEL
410,000,000
BTU/HR
BOILER
STEAM
850 PSIG - 825°F
ELECTRICITY
10,000 KW
Steam
TURBINE
ELECTRIC GENERATOR
13,400 HP
PROCESS STEAM
250,000#/HR
150 PSIG-500°F

Fuel requirements to:

Cogenerate ——	410,000,000 Btu/hr
Produce steam only (from Figure 2.3) -	370,000,000 Btu/hr
Produce electricity	40,000,000 Btu/hr

Generation efficiency: $\frac{3{,}412 \text{ Btu/kwh}}{4{,}000 \text{ Btu/kwh}} = 85.3\%$

III. TYPES OF COGENERATION SYSTEMS

There are many different kinds of cogeneration systems, each designed to produce a specific electrical (or mechanical) and thermal output required by a particular industrial process.

Although cogeneration facilities vary, certain generic cogeneration systems have evolved. Some of the more common types are described below.

A. Sequence of Heat Use

Cogeneration systems are characterized by the sequence of heat use as either "topping" or "bottoming" cycle systems. In a topping cycle facility, fuel is first used to produce electrical or mechanical power. Exhaust heat or steam is then used in an industrial application. The illustrative cogeneration system described in Section II (Figure 2.2) is of the topping cycle type.

In a bottoming cycle facility, fuel is first used to produce process heat. Then, exhaust heat or steam is used to generate either electrical or mechanical power.

B. Types of Prime Movers

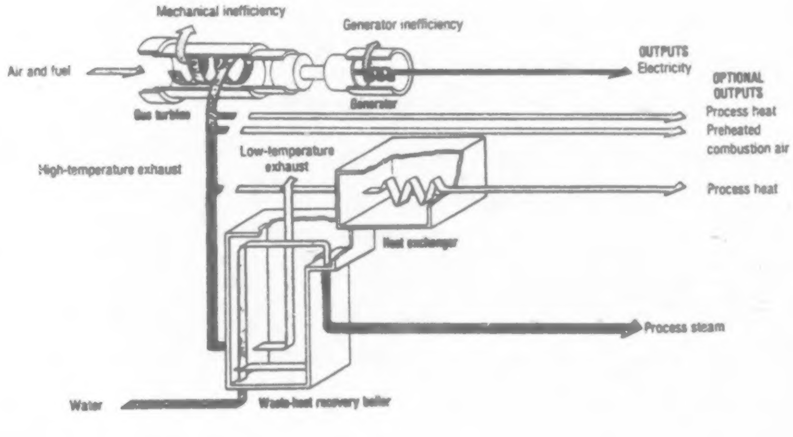
Cogeneration facilities are also characterized by their "prime movers." The most commonly utilized prime movers are:

1. Steam turbines - High-pressure, high-temperature steam is expanded through a turbine to generate electrical or mechanical power. Steam turbine facilities may be either topping or bottoming cycles. The illustrative system described in Section II (Figure 2.2) is of the steam turbine topping cycle configuration and is most closely related to conventional electrical generation. A variety of fuels may be used to

produce steam including coal, oil, gas, as well as waste products such as wood. Steam turbine systems usually are economical only in large installations as large quantities of steam are needed to reduce to an economic level the high capital cost per kw of electrical output. The Electric Power Research Institute (EPRI) estimates that 85-90 percent of industry's cogenerated electricity came from steam turbines in 1978.*/

2. Combustion turbine - Gas or oil is burned and expanded in a turbine to produce electrical or mechanical power. A relatively, large amount of clean, high quality heat is recovered in waste heat boilers to be used in industrial processes. Combustion turbines are used in a topping cycle configuration. Coal cannot be used as fuel unless it is first converted into a liquid or a gas. Generally, combustion turbine systems are characterized by lower capital costs in medium-sized installations and higher electrical/thermal ratios than steam turbines. Figure 3.1 illustrates the configuration of a combustion turbine facility — a gas turbine, topping cycle system.

FIGURE 3.1

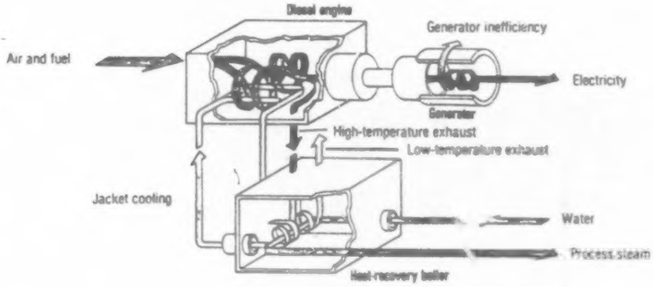

Mechanical inefficiency
Generator inefficiency
Air and fuel
OUTPUTS
Electricity
OPTIONAL OUTPUTS
Gas turbine
Generator
Process heat
Preheated combustion air
Low-temperature exhaust
High-temperature exhaust
Process heat
Heat exchanger
Process steam
Water
Waste-heat recovery boiler

---

*/ "Plugging Cogeneration Into The Grid," EPRI Journal, Electric Power Research Institute, Palo Alto, California, July/August 1981, page 8.

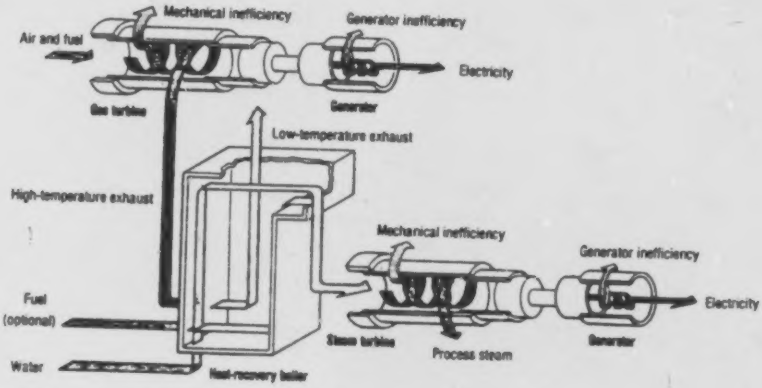
3. Reciprocating engine - Fuel (usually diesel) is burned in an internal combustion engine to produce electrical or mechanical power. Exhaust heat is recovered for use in industrial processes. Reciprocating engine systems are characterized by low capital costs in small installations, a high electrical/thermal ratio, a relatively small quantity of low quality waste heat, a relatively flat efficiency curve for operation at less than rated output, and rapid electrical output with no boiler warmup. Figure 3.2 illustrates a diesel-engine, topping cycle system.

FIGURE 3.2


Diesel engine
Generator inefficiency
Air and fuel
Electricity
Generator
High-temperature exhaust
Low-temperature exhaust
Jacket cooling
Water
Process steam
Heat-recovery boiler

4. Combined Cycle - A combined cycle system utilizes more than one prime mover. Combined cycle cogeneration systems may be configured in many different ways depending upon the particular electrical, mechanical and thermal requirements of the industrial process. Figure 3.3 illustrates a combined cycle cogeneration configuration. In this system, fuel is burned and expanded in a gas turbine to produce electricity. The waste heat is recovered in a heat-recovery boiler. Supplemental fuel may be burned in the boiler to increase the quantity of steam and the efficiency of the process. Steam from the boiler is used to turn a steam turbine and produce additional electricity. Exhaust steam from the steam turbine is used in the industrial process.

FIGURE 3.3


Mechanical inefficiency
Generator inefficiency
Air and fuel
Electricity
Gas turbine
Generator
Low-temperature exhaust
High-temperature exhaust
Mechanical inefficiency
Generator inefficiency
Fuel (optional)
Electricity
Steam turbine
Process steam
Generator
Water
Heat-recovery boiler

C. A Comparison of Cogeneration Systems

Individual cogeneration systems must be designed to meet the needs of the industrial process. As such, cogeneration facilities vary and it is difficult to compare precisely the advantages and disadvantages of each.

The General Accounting Office (GAO) compared selected characteristics for three topping cycle cogeneration systems.*/ Table 3.1 reproduces the results of the GAO comparison. These data are reproduced in this report to provide the reader with a "broad-brush" comparison of three types of cogeneration facilities. However, since each cogeneration facility differs, distinguishing features of a particular facility may differ from the illustrative features displayed in Table 3.1.

According to these data, steam turbines are characterized by high capital costs and low electrical/thermal ratios. Gas turbines and diesel cogeneration systems are characterized by substantially less capital investment and higher electrical/thermal ratios.

---

*/ Industrial Cogeneration -- What It Is, How It Works, Its Potential, U.S. General Accounting Office, Washington, D.C., EMD-80-7, April 29, 19830, page 1.

TABLE 3.1

Distinguishing Features of Topping Cycle Cogeneration Systems

	System		
Distinguishing features	Gas turbine	Diesel engine	Steam turbine
1. Type of fuel used	#2 light distillate oil or natural gas	Oil or gas	All types of fuel including coal
Advantage			Supports NEA conversion to coal objective
Disadvantage	Conflicts with NEA conversion to coal objective	Conflicts with NEA conversion to coal objective	
2. Capital investment required 1/	$500 per kW	$550 per kW	$1,250 per kW for coal 875 per kW for oil
Advantage	Low cost	Low cost	
Disadvantage			High cost
3. Efficiency in converting fuel to electricity 2/	5,500 Btu's per kWh	7,000 Btu's per kWh	4,500 Btu's per kWh
Advantage 3/			
Disadvantage 3/			
4. Electricity produced per unit of steam generated 2/	200 kWh per million Btu's of steam	400 kWh per million Btu's of steam	50 kWh per million Btu's of steam
Advantage 4/			
Disadvantage 4/			
5. Environmental effects	Gas produces little pollution	High nitrogen oxide and carbon monoxide emissions	High sulfur dioxide and particulate pollution with some coals
Advantage	No pollution control equipment needed		
Disadvantage		Exhaust may not meet purity requirements of some process heat applications	Expensive pollution control devices needed

1/ Total installed costs assuming 5-MW capacity.

2/ Federal Energy Administration and Thermal Electron Corporation, A Study of Inplant Electric Power Generation in the Chemical, Petroleum Refining and Paper and Pulp Industries. Final Report, 1976. p.2-1.

3/ While steam and gas turbines are more efficient than diesel engines, their fuel efficiency cannot be universally considered an advantage. For example, in situations with large electricity to steam demands, the diesel, although less efficient, would be the most advantageous to the cogenerator.

4/ Whether the amount of electricity produced is an advantage or disadvantage depends on the cogenerator's needs.

IV. INCENTIVES FOR COGENERATORS

In recent years industrials wishing to cogenerate faced four major obstacles.

- Some utilities were unwilling to interconnect with the cogenerator.
- Utilities were often unwilling to purchase the industrial's excess power or were willing to purchase such power only at unreasonably low rates.
- Some utilities charged discriminatory rates for backup, supplemental and maintenance power.
- A cogenerator which provided electricity to a utility could be considered a public utility and, as such, might be subject to extensive state and Federal regulation.

Some companies have not experienced difficulties in establishing adequate relationships with utilities. In fact, some companies find utilities (particularly utilities with severe capacity constraints) very cooperative and willing to negotiate fair and reasonable contracts with cogenerators.

On the other hand, some prospective cogenerators found utilities uncooperative and unwilling to negotiate at all or only in a prejudicial manner. Some of this resistance may have been caused by the fact that these utilities had substantial amounts of excess capacity and thus the cogenerator's additions to the utility's grid would have been of little value. However, some of the resistance is less understandable.

Over the past few years, the U.S. Congress has passed several bills providing incentives to industrial cogeneration and aimed at removing the obstacles. These incentives are outlined below.

A. The Public Utility Regulatory Policies Act

Congress passed the Public Utility Regulatory Policies Act of 1978 (PURPA) as part of the National Energy Act. PURPA is intended to promote the conservation and efficient use of energy. The Federal Energy Regulatory Commission (FERC) rules implementing PURPA Sections 201 and 210 provide incentives to encourage cogeneration as a means of efficient energy use.

1. Criteria for qualifying - Certain PURPA provisions apply only to "qualifying facilities" (QF's). Facilities must meet certain operating, efficiency and ownership criteria to be designated QF's. These criteria are set forth in a FERC rule and are outlined on Table 4.1.*/

2. Benefits of qualifying status - In February 1980, the FERC issued its final rule implementing Section 210 of PURPA.**/ This rule requires electric utilities to: (a) purchase any energy and capacity that is made available from a QF, (b) sell to any QF supplemental, back-up, maintenance or interruptible power, and (c) make any such interconnections with any QF as may be necessary. This rule also implements the PURPA provisions excluding QF's from some of the provisions of certain Federal and state laws including the Federal Power Act and the Public Utility Holding Company Act.

(a) Rates for purchases from QF's - Utility rate regulation traditionally allows utilities an opportunity to recover reasonable costs and earn a fair rate of return on investment. This traditional ratemaking process requires regulators to examine the books and records of the utility to determine whether or not the costs incurred are reasonable.

---

*/ Small Power Production and Cogeneration Facilities -- Qualifying Status, Final Rule, Federal Energy Regulatory Commission, 45 Federal Register 17972, March 20, 1980.

**/ Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, Final Rule, Federal Energy Regulatory Commission, 45 Federal Register 12214, February 25, 1980.

TABLE 4.1

Operating, Efficiency and Ownership Criteria for Qualifying Facilities*/

Type of Cogeneration Facility	Operating Standard	Efficiency Standard
	(Section 292.205)	(Section 292.205)
1. Topping-cycle	(a)(1) The useful thermal energy output of the facility must, during any calendar year period, be no less than five percent of the total energy output.	(a)(2)(i) For any topping-cycle cogeneration facility for which any of the energy input is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output of the facility plus one-half the useful thermal energy output, during any calendar year period must: (A) Subject to paragraph (a)(2)(i)(B) of this section be no less than 42.5 percent of the total energy input of natural gas and oil to the facility; or (B) If the useful thermal energy output is less than 15 percent of the total energy output of the facility, be no less than 45 percent of the total energy input of natural gas and oil to the facility. (a)(2)(ii) For any topping-cycle cogeneration facility not subject to paragraph (a)(2)(i) of this section there is no efficiency standard.
2. Bottoming-cycle	None	(b)(1) For any bottoming-cycle cogeneration facility for which any of the energy input as supplementary firing is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output of the facility must, during any calendar year period, be no less than 45 percent of the energy input of natural gas and oil for supplementary firing. (b)(2) For any bottoming-cycle cogeneration facility not covered by subparagraph (b)(1) of this paragraph, there is no efficiency standard.

Ownership Criteria (Section 292.206):

No more than 50 percent of the equity interest of a QF may be owned by an electric utility or utilities, or by an electric utility holding company, or any combination thereof.

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*/ Small Power Production and Cogeneration Facilities — Qualifying Status, Final Rule, op. cit.

PURPA changed the way that regulators view utility purchases of power from cogenerators. Traditional utility regulation sets prices for the purchase of cogenerated power at the cogenerator's costs plus a reasonable rate of return. PURPA requires regulators to look at changes in the utility's costs caused by the utility's purchase of cogenerated power. PURPA does not allow utilities to purchase cogenerated power at rates that exceed the costs that the utility avoids by purchasing this power. PURPA requires electric utilities to purchase any energy and capacity that is made available from a qualified facility (QF). PURPA further requires that the FERC rules implementing Sections 201 and 210 shall ensure that the rates for purchases of cogenerated power (1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and (2) shall not discriminate against the QF.

PURPA states that rates for purchases of cogenerated power shall not exceed the "...incremental cost to the electric utility of alternative electric energy..." The incremental cost is defined by PURPA as "...the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source."

The FERC's rule implementing this PURPA mandate requires utilities to purchase electricity from QF's. However, the rule differentiates between "new" QF's (those built after November 9, 1978) and all other "old" QF's. The rule specifies that utilities must purchase electricity from new QF's at a rate that equals the utility's full "avoided cost" unless a state regulatory authority determines that a lower rate is just and reasonable, nondiscriminatory and sufficient to encourage cogeneration. The rule does not affect rates for purchases from old QF's. The FERC defines avoided costs the same as PURPA's "incremental cost of alternative energy." The rule requires utilities to establish standard rates for purchases from QF's of 100 kw or less.

If a QF offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing utility to avoid the need to construct a generating unit, then the FERC rule requires that the rates for purchase from the qualifying facility must be based upon the avoided capital costs of the new facility as well as the avoided energy costs.

The FERC rule lists several factors which may be taken into account in calculating avoided costs. These factors include the duration of the obligation, termination notice requirement and sanctions for noncompliance, the expected reliability of the qualifying facility, the ability of the utility to dispatch the qualifying facility, and the extent to which scheduled outages of the qualifying facility can be coordinated with scheduled outages of the utility's facilities.

State regulatory authorities were required to implement a cogeneration (and small power production) program by March 19, 1981, that conforms with the FERC rule. As of February 1983, forty-two states have issued final rules according to the Edison Electric Institute.*/

The specifics of each state's rules differ substantially, although most offer fixed rate tariffs for QF's of 100 kw or less, as required by the FERC rule. Most states also have formulated either a generic avoided cost rate or a methodology for calculating avoided costs on a case-by-case basis for QF's larger than 100 kw.

(b) Rates for sales to QF's - PURPA requires the FERC to prescribe rules relating to power sales by utilities to cogenerators. These rules are intended to both encourage cogeneration and require electric utilities to sell electric energy to QF's. PURPA states that the FERC rules are to ensure that the rates charged for such power sales shall (1) be just and reasonable and in the public interest, and (2) not discriminate against the QF.

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*/ "Dispersed Energy Update," URAP Alert, Edison Electric Institute, Washington, D.C., Vol. 5, No. 4, February 18, 1983, pages 3-6. A copy of this survey is reproduced in an appendix.

In the Statement of Managers accompanying PURPA, the Conferees state that the phrase "just and reasonable" is intended to refer to traditional utility ratemaking concepts. The QF shall not pay any more or any less than is otherwise justified by the utility's cost of providing the service. The Conferees state that the phrase "not discriminate" is used to preclude utilities from charging "unjust and non-cost based rates...solely to discourage cogeneration." However, the Conferees also state that "this phrase should not be construed to permit discrimination against the electric customers of an electric utility in formulating rates under this provision."

The FERC rule implementing PURPA Section 210 requires that, upon the request of a QF, each electric utility shall provide supplementary, back-up and maintenance power at just and reasonable, nondiscriminatory rates.*/ The requirement to provide power may be waived by the appropriate state regulatory authority if it is demonstrated that compliance with the requirement would impair the utility's ability to render adequate service to its customers or place an undue burden on the electric utility.

Additionally, the FERC rule requires that the rates for sales of back-up or maintenance power shall (1) not be based upon an assumption unsupported by factual data that forced outages or other reductions in electric output by all QF's on a system will occur simultaneously, or during the system peak, or both and (2) take into account the extent to which scheduled outages of the QF's can be usefully coordinated with scheduled outages of the utility's facilities.

(c) Interconnections - Technically, an "interconnection" is any physical connection that permits electricity to flow from one entity to another. Concerns over safety and the lack of a need for power may make utilities hesitant to interconnect with cogenerators in such a way that power can flow both to and from the cogenerator. Failure to adhere to adequate interconnection safeguards can reduce the reliability of a utility's system, increase the possiblity of system instabilities, make voltage control ineffective and endanger human safety. Protective devices are available that allow cogenerators to operate safely in parallel with a utility's system. These devices promptly disconnect the cogenerator from the utility if an abnormal operation or fault occurs. The safety concerns of the utility should be alleviated as long as the utility specifies and controls the design and operating requirements of necessary protective devices.

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*/ Section 292.305 of the FERC's Final rule, Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, 45 Federal Register 12216, February 25, 1980. This rule also requires electric utilities to offer interruptible power. This requirement is discussed in a separate ELCON document.

A utility's need for power can influence its desire to interconnect. A capacity constrained utility may be very interested in purchasing power from a cogenerator and thus readily may interconnect. Alternatively, a utility with a very large reserve margin has little need for cogenerated power and thus may be hesitant to interconnect.

Prior to PURPA, any nonutility QF desiring an interconnection with a utility was bound by the cumbersome provisions of the Federal Power Act (FPA). Sections 210 and 212 of the FPA provide that FERC may issue such an interconnection order only if the interconnection:

- is in the public interest;
- would encourage overall conservation of energy or capital, optimize the efficiency of the use of facilities and resources, or improve a utility systems reliability;
- is not likely to result in a "reasonably ascertainable uncompensated economic loss" for any utility or cogenerator;
- will not place an "undue burden" on any party;
- will not "unreasonably impair the reliability" of the utility; and
- will not "impair" the utility's ability to render adequate service to its customers.

The FPA also requires the FERC to give appropriate notice and afford an evidentiary hearing before issuing any such order.

These comprehensive FPA requirements allowed utilities to resort to protracted hearing procedures to avoid establishing interconnections with QF's if they so desired. PURPA amended the FPA by providing the FERC the authority to order such an interconnection without adhering to the cumbersome FPA procedures. However, Section 210(e)(3) of PURPA also contains the following language:

> No qualifying small power production facility or qualifying cogeneration facility may be exempted under this subsection from...
>
> (B) the provisions of Section 210, 211, or 212 of the Federal Power Act...or the necessary authorities for the enforcement of any such provision of the Federal Power Act...

The FERC promulgated a rule under this PURPA authority which, in part, states: "(A)ny electric utility shall make such interconnections with any qualifying facility as may be necessary to accomplish purchases or sales under this subpart."

The rule requires each QF to pay any interconnection costs which the state public utility commission may assess against the QF on a nondiscriminatory basis.

(d) Exemption from Certain Federal and State Laws and Regulations - Prior to PURPA, industrial cogenerators could be subjected to public utility regulation if they produced and sold electric power. The threat of cumbersome and expensive public utility regulation deferred the development of cogeneration.

The FERC rules exempt QF's from certain Federal and state laws and regulations including:

- A qualifying cogeneration facility is not considered an "electric utility company" as defined in the Public Utility Holding Company Act of 1935, and is therefore exempt from the Act.

- Qualifying cogeneration facilities are exempt from certain burdensome provisions of the Federal Power Act.
- Qualifying cogeneration facilities are exempt from the ratemaking and electric utility financial and organizational regulations authorized under state laws, except for those state laws and regulations which implement the provisions of PURPA Section 210 and the final regulations under PURPA Section 210.

B. The Powerplant and Industrial Fuel Use Act

The purpose of the Powerplant and Industrial Fuel Use Act of 1978 (FUA) is to promote the use of coal and energy sources other than natural gas and petroleum. The FUA limits and prohibits the use of natural gas and petroleum by certain powerplants and major fuel burning installations. Sections 212(c) and 312(c) of the FUA (relating to "new" and "existing" facilities, respectively) provide for permanent exemptions from these limitations and prohibitions for cogeneration facilities which qualify under the regulations implementing those sections.

C. The Natural Gas Policy Act

The Natural Gas Policy Act of 1978 (NGPA) requires that the natural gas used in certain industrial facilities be subject to incremental pricing by means of surcharges. Section 206 of the NGPA exempts QF's from incremental pricing. The exemption applies to all natural gas used in any QF, other than gas used for supplementary firing if such gas is not also used in a "cogeneration" mode.

D. Ruling of the Court of Appeals

In 1980, several utilities challenged certain aspects of the FERC's rules.*/ These utilities challenged four segments of the FERC's rules under PURPA: (1) the full avoided cost rule, (2) the mandatory interconnection rule, (3) the absence of fuel use standards in the cogenerator qualifying criteria and (4) the simultaneous purchase and sale rule.

On January 22, 1982, the D.C. Circuit Court vacated the former two rules and upheld the latter two rules. Although not a complete victory for the utilities, most observers felt that the two rules vacated in the AEP decision were the most significant rules challenged and, more importantly, the two most important incentives for cogeneration. Each is discussed below.

1. *The Appeals Court's Avoided Cost Ruling* - The utilities argued that the FERC, by ordering that the purchase rate be equal to the full avoided cost in every case, simply adopted as a uniform rule the *maximum* purchase rate specified in PURPA. The utilities stated that Congress made a clear distinction between a "just and reasonable" rate and a rate based on full avoided costs, although the two *may* coincide. By requiring the utility to pay the cogenerator exactly what it would have cost the utility to produce the power itself or buy from another source, the utilities argue that the FERC rule forecloses the states from ordering a sharing of any of the benefits of the transaction with the other customers of the utility.

The FERC referred to the Conference Report accompanying PURPA which states that "...the purchase by the utility of the cogenerator's or small power

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*/ *American Electric Power Service Corp., et. al., v. FERC*, No. 80-1789, U.S. Court of Appeals for the District of Columbia Circuit, herein *AEP v. FERC*.

producer's power should not be burdened by the same examination as are utility rate applications, but rather in a less burdensome manner." The FERC argued that a "split-the-savings" rule would result in precisely the sort of utilities-type regulation which PURPA was designed to avoid. The Commission said that any benefits accruing to utility customers from sharing the benefits would lead to "insignificant" rate reductions. Finally, the FERC asserted that allocating all the savings to cogenerators would provide the greatest encouragement for a higher cogeneration growth rate.

On January 22, 1982, the Appeals Court issued its decision. The Court found the FERC's case "inadequate" and vacated the full avoided cost rule.

The Court said that the rates utilities pay QF's, in addition to not discriminating against cogenerators, also must be "just and reasonable to the electric customers of the electric utility" and "in the public interest." The Court stated that Congress could have required the FERC to set rates at full avoided cost. However, Congress did not do so. Instead, it specified three other criteria (the interests of the public, cogenerators and the customers of the utilities) which the FERC was to consider in establishing cogeneration ratemaking policy.

The Court found that the FERC did not balance the interests of the three parties adequately. Instead, the Commission came to the "simplistic and uniform conclusion that the full avoided cost standard would be just and reasonable in every case and that this was necessary to encourage cogeneration in every case."

The Court ordered the FERC to take a harder look at a percentage of avoided cost approach. Such an approach might, for example, entail the FERC setting a specific percentage or permitting state commissions to set rates within a range; e.g., 80-100 percent.

2. The Appeals Court's Interconnection Ruling - The utilities argued that by requiring any utility to make interconnections with any cogenerator that the FERC designates, the FERC would in effect exempt QF's from other procedural and substantive requirements of Sections 210 and 212 of the FPA and deprive utilities of the safeguards afforded by these provisions.

The FERC argued that compliance with the literal meaning of the statutory sections would impose an undue burden upon cogenerators. The FERC's argument relies primarily on the specific authority given to the FERC to order interconnections. In essence, the FERC argued that PURPA gave the FERC specific authority to require interconnections without adhering to the cumbersome FPA procedures and that other statutory provisions cannot be read as limiting that authority.

The Appeals Court found the FERC's argument with regard to interconnections "wholly unconvincing" on January 22, 1982. The Court said that the general grant of authority in FPA Section 212(e) does not give the FERC "...a mandate to consign detailed provisions of PURPA itself to the wastebasket as meaningless surplusage." The Court thus vacated the Commission's rule, but said that the FERC could "adopt streamlined procedures."

E. Ruling of the Supreme Court

On May 16, 1983, the Supreme Court of the United States reversed the U.S. Court of Appeals for the District of Columbia Circuit and upheld the FERC's full avoided cost and mandatory interconnection rules in an 8-0 decision.*/ Given the unambiguous nature of the Supreme Court's opinion, the remand to the Court of Appeals for further proceedings consistent with the Supreme Court's opinion should be uneventful.

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*/ American Paper Institute, Inc., v. American Electric Power Service Corp., et. al., No. 82-34, Supreme Court of the United States, Slip Opinion, May 16, 1983.

The Supreme Court's unanimous opinion, written by Justice Marshall (Justice Powell abstained), should lay to rest the uncertainties surrounding cogeneration which followed the Court of Appeals decision. Moreover, it makes clear that the present Supreme Court will give FERC — and other federal agencies -- wide latitude in implementing statutory directives. The Court said it need only conclude that the agency rule under review is a reasonable interpretation; it need not be the most compelling one, or even the same one that the Court would have reached had the question arisen in the first instance in judicial proceedings.

1. The Supreme Court's Avoided Cost Ruling - The Supreme Court stated that the full avoided cost rule plainly satisfies the requirement that the rule must not discriminate against QF's. The Court said that the FERC recognized that the rule would not directly provide any rate savings to electric utility consumers. However, the Court agreed with the FERC which said that the rule could provide a significant incentive for a higher growth rate of cogeneration and small power production, and that ratepayers and the nation as a whole will benefit from the decreased reliance on scarce fossil fuels, such as oil and gas, and the more efficient use of energy.

The Court ruled that the FERC would have encountered considerable difficulty had it attempted to determine an appropriate rate less than full avoided cost, and that a lower rate would discourage the development of QF's. Additionally, the full avoided cost rule is not as inflexible as it might appear at first glance, for contracts may be negotiated at lower rates and FERC may grant waivers of the rule.

The Supreme Court concluded that under these circumstances, "...it was not unreasonable for the Commission to prescribe the maximum rate authorized by PURPA."

In accepting FERC's arguments that the full avoided cost rule was "just and reasonable to the electrical consumers ... and the public interest," the Court emphasized three points that were largely overlooked by the Court of Appeals:

a) Full avoided cost rates are not mandatory. "Any state regulatory authority and any nonregulated utility may apply to the commission for a waiver of the rule."

b) A qualifying facility and a utility may negotiate a contract setting a price that is less than full avoided cost. The Court did not consider this unrealistic in view of the possibility that the full avoided cost regulations may be amended at some later date, after FERC acquires additional experience implementing this complicated regulatory program. A long-term contract with a guaranteed rate could be preferable to the risk of FERC promulgating new regulations mandating a rate significantly less than full avoided cost.

c) The full avoided cost rule was not unreasonable in light of FERC's experience in the area of cogeneration economics. Inherent in the Court's opinion is the suggestion that, as FERC's experience develops, it should consider whether a lower rate is justified.

2. The Supreme Court's Interconnection Ruling - Sections 210 and 212 of the Federal Power Act provide that the FERC may issue an interconnection order only if certain comprehensive procedures, including evidentiary hearings, are followed. PURPA provided the FERC the authority to bypass these cumbersome provisions. However, PURPA Section 210(e)(3) clouded the FERC's authority by stating that QF's may not be "exempted" from the provisions of Section 210 or 212 of the FPA. (See pages 22-23 above for a more complete discussion.)

The Supreme Court ruled that absent Section 210(e)(3), there would be no doubt as to the validity of the FERC's interconnection rule. This Court said that the critical question is whether Section 210(e)(3) deprives the FERC of its authority to bypass the FPA provisions.

The Court said that the purposes of PURPA make it most unlikely that Congress could have intended that an evidentiary hearing be held for every interconnection necessary to consummate a purchase or sale of electricity authorized by the Act. According to the Court, evidentiary hearings would seriously impede the very development of cogeneration and small power production that Congress sought to facilitate. The Court notes that the FERC's interconnection rule does not immunize QF's from Sections 210 and 212 of the FPA, but rather permits QF's to take certain steps to require other parties (i.e., electric utilities) to make interconnections.

In its decision, the Supreme Court clarified an issue that has concerned several QF's: whether a QF can be a target of an interconnection order. The Court said:

> "[T]he Commission's interconnection rule does not immunize qualifying facilities from the only requirement that §§ 210 and 212 of the [Federal Power Act] do directly impose on them — the requirement that they obey an interconnection order issued under those provisions. Qualifying facilities remain subject to applications by other facilities for orders requiring them to make interconnections. The Commission's rule simply permits qualifying facilities to take certain steps to require other parties, namely, electric utilities, to make interconnections. (Emphasis in original.)

Additionally, the Court observed that the legislative history of Sections 210, 211 and 212 of the FPA indicates that these provisions were intended to address a different situation. Congress was concerned with the refusal of some intrastate utilities to make interconnections with other systems because, had they done so, they would have become subject to Federal regulation. Sections 210, 211 and 212 were intended to give the authority to the FERC to order interconnections where they would "enhance the reliability of the nation's electric power systems and optimize the use of its generating capacity."

The Court ruled that the FERC's interpretation of the law is a reasonable one, and that the Court of Appeals erred in rejecting that interpretation. Accordingly, the FERC's interconnection rule was upheld.

F. Status of Federal Legislation:

During the 97th Congress, bills affecting cogenerators were introduced in both Houses of Congress. S. 1885 was introduced in the spring of 1982 to remove the existing 50 percent restriction on utility ownership of QF's (the "50 percent cap"). A hearing was held on S. 1885 on April 19, 1982, by the Senate Subcommittee on Energy Regulation. Utilities testified in favor and all other interest groups opposed removal of the 50 percent cap.

Senator Gordon J. Humphrey (R-NH), Chairman of that Subcommittee, introduced amendments to S. 1885 on May 18, 1982. These amendments were intended to reverse the AEP decision described above. Specifically, S. 1885 as amended would:

1. remove the "50 percent cap,"
2. guarantee an interconnection for all QF's, and
3. require that utilities pay QF's full avoided costs for purchased power.

A hearing was held on S. 1885, as amended, on May 21, 1982. Nearly all appearing before the Subcommittee opposed the bill. Utilities could not support the "court fix," while cogenerators could not support the removal of the "50 percent cap."

Following the Senate action, H.R. 6500 was introduced in the House. This bill did not address the 50 percent cap. H.R. 6500 would guarantee an interconnection and mandate a full avoided cost rate for utility purchases of QF power unless a state PUC determined that some other rate would be sufficient to encourage cogeneration, would not discriminate against QF's and would be in the ratepayers' and the public's interest.

A hearing was held on H.R. 6500 on June 15, 1982, by the House Subcommittee on Energy Conservation and Power. Cogenerators strongly supported the bill, while utilities strongly opposed it. Markup on H.R. 6500 was postponed several times due to scheduling conflicts with the full committee and lack of quorums.

Congress adjourned in December 1982 without completing action on any cogeneration legislation. Bills similar to those debated during 1982 are expected to be introduced in the 98th Congress.

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APPENDIX

State-by-State Report on the Implementation of Section 210 of PURPA

dispersed energy update

State Report on the Implementation of PURPA Section 210

February 18, 1983

State	Status of Process	Date of Final Order
Alabama	Rates for purchasing energy from QFs of 100 KW or less adopted. Larger QFs negotiating rates with utilities. Some requested that commission also establish their rates.	March 24, 1981
Alaska	Commission issued proposed rulemaking on June 16, 1981 to establish conditions for PURPA implementation. Hearings held July 2, 1981. Comment filing was extended to August 29, 1981. Final order was issued on June 23, 1982.	June 23, 1982
Arizona	Hearing held June 16, 1981 to consider issuing rule. Commission issued compromise order to implement PURPA Section 210. Arizona Public Service Co. applied for a new rate hearing to take place in 1983.	July 22, 1981
Arkansas	Proposed order issued in March 1981. Arkansas P&L rate case decided in June. AP&L case to guide in determining utilities' tariffs on data submissions. Company tariffs to be decided case-by-case. Proposed rules issued April 29; the draft order is still before the commission.	
California	Final Staff report on pricing standards submitted January 20, 1981 and pending commission's rulemaking decision. Interim order issued May 19, 1981. Final order issued January 21, effective February 1. Decision No. 82-12-120 further clarifies and defines the relationship between public utilities and alternate generation resources.	January 21, 1982
Colorado	Proposed rule filed September 23, 1980. Hearing Examiner issued Examiner issued recommendation May 6, 1981. Order (#C82-73) issued January 12; effective February 1. Commission stayed order March 23 (in Dec. # C82-436). Final order issued October 14, 1982 pending outcome of petitions for rehearing. Petitions were denied and October 14th rule became effective December 13, 1982.	October 14, 1982
Connecticut	Cogeneration directives issued in individual rate cases for Hartford Electric Light Co., Connecticut Light & Power, and United Illuminating Co. Final decision reached on United Illuminating Co. rates. Final decision signed November 24 and issued November 25, 1981. Legislation was passed the first week in October 1982, providing for 20 year contracts to encourage cogenerators.	November 25, 1981
Delaware	Utilities filed rates and testimony. Hearings held in May. Hearing Examiner's report issued in October 1981. Final order (#2321) incorporating Delmarva tariffs issued February 16; effective March 1. Hearings have been completed.	February 16, 1982
District of Columbia	Hearing Agent issued an opinion and recommended decision on August 3, 1982, in Order No. 7638. The DC PSC issued Order No. 7640 on August 4, 1982, adopting the Hearing Agent's opinion and recommendation.	August 4, 1982
Florida	Final rules adopted April 22, 1981. Rate schedules filed by utilities by June 18, 1981. Rates set August 11, 1981. FP&L has challenged the state commission's jurisdiction over interconnection of QFs; the decision is pending before the state Supreme Court. Amendments were made to all cost-benefit calculations which include capacity credit.	April 22, 1981
Georgia	Draft order on power purchase rates written July 1, 1981 without figures. QFs free to negotiate individually with utilities. The Staff drafted regulations and sent them to interested parties for comments.	

State	Status of Process	Date of Final Order
Hawaii	Proposed rules issued January 23, 1981. Hearings held in March 1981. Final rule adopted September 25, 1981; signed by Governor on February 6; effective February 18, 1982. Rules for standard purchases of 100 kw or less are under protest, wind generators say the rates are not high enough. Hearings should he held early in 1983.	Sept. 25, 1981
Idaho	Final order issued June 1980. Two clarifying orders issued since. Standard contracts for QFs over 100 KW and standard tariffs for QFs under 100 KW. Hearings on avoided costs held; some contracts signed. Two rate cases are before the Idaho commission; one concerns the future resources of Idaho Power and the second is about avoided cost and annual update. No dates have been set for the hearings.	June 1980
Illinois	Final order (#214) issued March 20, 1981. Companies filed tariffs by June 20; negotiations ongoing between utilities and QFs. Commission refining cost methodology; utility-filed tariffs in effect. The commission is reviewing the annual renewal of avoided cost rates.	March 20, 1981
Indiana	Final order issued March 20, 1981. Companies filed tariffs on June 3, negotiations between utilities and QFs continuing independent of commission guidance. In response to H&R Act 1109, the commission reconsidering rules to recognize the "capital element:" The deadline for review is June 30, 1983.	March 20, 1981
Iowa	Final order issued March 20, 1981 and effective May 20, 1981. All tariffs filed by investor-owned utilities suspended for possible review and/or hearing. Of the six tariffs filed three have been reviewed and finalized. Staff continuing to meet with the other utilities to modify the scope of the rate filings.	March 20, 1981
Kansas	Commission Staff proposed using avoided costs. Hearings held in April 1981. Final order issued April 28. Order on rehearing was signed November 5 making minor modifications to the final order. Utilities have 60 days to file.	April 28, 1982
Kentucky	Hearings held March 6, 1981. Proposed regulation published on October 1, 1981 and hearings held on October 15, 1981. The commission issued its regulations April 7, 1982.	April 7, 1982
Louisiana	Hearings held in February 1981 and Task Force formed. Task Force proposed rule, but further hearings requested. Commission reconciling differences between Task Force members. Final Order No. U-14964 was issued November 24.	November 24, 1982
Maine	Final rule issued May 7, 1981. Central Maine Power's petition denied on July 2, 1981. August 6, 1981 order rejected Bangor Hydro-Electric rates. Long-term QF contract rates investigation planned. The state re-adopted the substantive portion of the rule (210) with minor adaptations. Long term rates still pending.	May 7, 1981
Maryland	Final order (No. 65913) issued August 23. Adopts Hearing Examiner's proposed order, but remands for further hearing the calculation of capacity payments. The order determined that QF standards may be implemented through the tariff process.	August 23, 1982
Massachusetts	Proposed rule issued December 24, 1980 and hearings completed. Final order (DPU 535) issued July 25, 1981. Rates filed September 15, 1981. Staff to amend final order to simplify rate proceedings, but not ratemaking methods. The amendments are still in draft form and should be available soon.	July 25, 1981
Michigan	March 17, 1981 commission order set interim rates. Settlement conference held December 2, 1981. A settlement has been adopted for each utility using a general methodology. The decision was issued on August 27, 1982. Utilities have 90 days to file tariffs.	August 27, 1982
Minnesota	Proposed Rule issued February 1980. Hearings began in May 1981. A hearing was scheduled to review the rules proposed in March 1982. A final rule is expected in early 1983.	

State	Status of Process	Date of Final Order
Mississippi	Generic hearings held April 29, 1981. QFs under 100 KW to submit proposed rates, with larger QFs to be handled case-by-case. Another generic hearing held in early August 1981. The Staff is optimistic about cogeneration contract possibilities. However, they do not expect any action until 1983.	
Missouri	Final rule issued April 7, 1981 and effective May 15, 1981. Utilities filed rates September 15, 1982: one approved; remainder suspended. Four revised tariffs filed in April 1982.	April 7, 1981
Montana	Final rules issued January 4, 1982. Second Order issued February 16, 1982 (4865A) revising the avoided cost method. The commission issued order (4865B) to address utilities' concerns in late June 1982.	January 4, 1982
Nevada	Interim rule issued March 4, 1981. Hearings held on July 21, 1981 to determine need for permanent rule. General Order No.32 adopted August 4, 1981. The avoided cost rates are subject to review quarterly.	August 4, 1981
New Hampshire	Current small power producer rates set in June 1980. Final order on simultaneous purchase and sale, and interconnections issued March 1981. A decision (Doc. 8133) which will determine avoided costs and rates for distribution utilities is still pending. Staff study (81312) on electric power supply and demand over the next 15 years was submitted to the commission October 1, 1982.	March 20, 1982
New Jersey	Final order issued October 13, 1981; utilities must file tariffs by November 16, 1981. Wheeling of rates began February 16, 1982; no wheeling order yet issued.	October 14, 1981
New Mexico	Order No. 37 approved in March 1981 requiring companies to submit interim tariffs within 30 days. Task Force study of tariffs and other contract issues completed. The commission has adopted amendments to G.O. #37. They cover interconnections, safety standards and a standard interconnection agreement. Revisions were approved December 13, 1982.	March, 1981
New York	Proposed rules issued January 7, 1981. Final order issued May 12 which requires full avoided cost. The NY PSC is assisting in the negotiations between QFs and utilities by devising financing methods appealing to both parties. Comments have been received from the utilities on buy-back proposals.	May 12, 1982
North Carolina	Recommended Order issued March 10, 1981. Order issued September 21,1981. VEPCO, Carolina P&L, and Duke rates approved December 14, 1981. Proposed avoided costs were filed with the commission by June 30, 1982. Hearings were set for December 14 to review details of rates to be paid to QFs.	September 21, 1981
North Dakota	Final rules issued March 30, 1981. Three utilities filed rate schedules: all approved.	March 30, 1981
Ohio	Evidentiary hearings held in March 1981. Interim order for QFs of 100 kw or less was signed November 17. Negotiations are conducted for any facility larger than 100 kw.	November 17, 1982
Oklahoma	Two final orders issued March 26, 1981. One set rules for QF power purchases and the other to set rates for QFs of 100 KW or less. OG&E has filed avoided cost rates. There is a joint filing of Public Service Co. and Alternate Energy Systems, Inc. for approval of buy-back rates.	March 26, 1981
Oregon	Evidentiary hearings held. Proposed order issued April 6, 1981 set rates for QFs of 100 KW or less. Final order (81-755) issued October 29, 1981. OR PUC issued Order No. 82-515 on July 20, 1982, which set rates using a base rate concept and Order No. 82-514 that covers interactions between utilities and QFs.	October 29, 1981
Pennsylvania	Proposed rule approved April 10, 1981. Proposed final rule issued February 3, 1982. Final rule issued on September 24, 1982. Utility payment for purchases from QFs is based on energy and capacity credits instead of using avoided cost provisions.	September 24, 1982

update

State	Status of Process	Date of Final Order
Rhode Island	Final order issued March 20, 1981. Rates filed. Compliance orders have been issued approving tariffs for all utilities in the state.	March 20, 1981
South Carolina	Final rules issued March 20, 1981. Some rates approved. Carolina P&L's new rate which gives more credit to QFs has been approved.	March 20, 1981
South Dakota	Hearings held January 6-7, 1982. The final order (F-3365) was issued December 14, 1982. The order set standard rates for purchases from QFs of 100 KW or less.	December 14, 1982
Texas	Final Task Force report submitted. Proposed rules (052.02;050.58) issued June 5, 1981. Final rule adopted on August 20, 1981; effective on September 13, 1981.	August 20, 1981
Utah	Final order issued in April 1981. Commission report criticized existing avoided cost methodology. Comments on report solicited. Final order may be revised.	April 9, 1981
Vermont	Order No. 65 approved April 7, 1981. Final rule issued June 18; revised order issue June 19, 1981. There is a movement to change the manner in which the avoided cost is calculated VT PSB issued new final rule repealing June 18 order. The order new establishes a purchasing agent to purchase QF power for utilities.	June 18, 1981
Virginia	Interim rule for VEPCO and final rule for APCO issued. Other utilities filing rate schedules. Final rule issued June 19, 1981. Arbitration is required on individual basis between large individual producers and utilities.	June 19, 1981
Washington	Final rules adopted January 28, 1981. Two utilities have filed rates. The rates electric companies pay vary with the stream flows; rates are lower when the level of the rivers are highest.	January 28, 1981
West Virginia	General Order No. 207 issued in January 1981, hearing held in March held in March on QFs of 100 KW or less. Proposed rule for larger QFs approved. No final rule will be issued until the avoided cost question has been resolved.	
Wisconsin	Rates in effect for large investor-owned utilities. Hearings continuing; report on avoided costs, wheeling and stand-by provisions completed. Commission wrote utilities on January 28, 1982 requiring them to file net energy billing for smaller utilities. Commission issued April report setting avoided cost guidelines for buy-back rates; is waiting for utility responses before it determines avoided costs and rates for all utilities.	
Wyoming	Commission issued General Order No. 47 based on FERC rules with added requirement for safety and reliability. Utilities filed "experimental" rate schedules. DOE-funded cogeneration study underway.	

SOURCE: URAP Alert Dispersed Energy Update, February 18, 1983. Copyright Edison Electric Institute, 1111 19th Street, N.W., Washington, D.C. 20036.

STATES' COGENERATION RATE-SETTING UNDER PURPA, Part 1

(Part 2 will appear Sept. 16)

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), state regulatory agencies were required to implement mechanisms to ensure that cogenerators receive (among other things) just, reasonable and non-discriminatory rates for electricity sold to electric utilities. To encourage cogeneration, these "buyback" rates were to be equal to the costs a utility saves by not having to generate or buy elsewhere the power it obtains from a cogenerator. The chief avoided cost components of buyback rates are the energy (fuel) credit and the capacity (construction) credit. Planning and calculating the capacity credit is a varied and often controversial process, and the rules are subject to change.

The status of states' PURPA cogeneration proceedings and cogeneration buyback rates for most major utilities is listed below. Information was supplied by state utility commissions, utilities and the law firm Chadbourne, Parke, Whiteside & Wolff, N.Y.

"QF" (qualifying facility) refers to cogenerators and other small power producers under PURPA. QFs are generally responsible for the cost of interconnection with the utility; the chart omits these fees and those for "administration." Some utilities also set special backup power rates for QFs who have the right to backup power under PURPA. Where standard offerings do not apply and the utility and cogenerator agree on rates and terms, the commission can arbitrate. In many cases, small-QF standard offerings act as negotiating bases for larger-QF contracts. Rates below do not necessarily apply to systems for which construction began before Nov. 9, 1978.

STATE	STATUS & RULES	RATES	CONTACT
ALABAMA Public Service Commission	Rates adopted for units no larger than 100 kw; no avoided capacity payment included. Larger QFs negotiate with utility. PSC: QFs must pay 100% of highest demand rate of previous 12 months to secure backup power (compared to a standard ratchet clause of 80%). Cogenerators' protest to secure capacity payments, lower backup rate is scheduled for October but postponed at their request.	**Alabama Power Co.:** Peak summer (Jun-Oct) 3.86 c/kwh, winter 2.61 c/kwh; off-peak (and non-time-of-day rates) summer 3.41 c/kwh, winter 2.33 c/kwh. Actual negotiated rates for larger QFs, based on 2-year contracts signed in 1983 and renewed in 1985: summer peak 2.602 c/kwh, off-peak 2.186 c/kwh; winter peak 2.373 c/kwh, off-peak 2.151 c/kwh.	Robert E. Reed, PSC, (205) 261-5000
ALASKA Public Utilities Commission	Rates in effect for non-firm cogenerators no larger than 100 kw. (Some rates change slightly as often as each month.) Larger cogenerators negotiate.	For non-firm QFs no larger than 100 kw: **Anchorage Municipal Light & Power Dept.:** 2.024 c/kwh **Chugach Electric Association Inc.:** 1.35 c/kwh **Homer Electric Association Inc.:** 3.005 c/kwh **Golden Valley Electric Association Inc.:** 4.251 c/kwh **Alaska Electric Light & Power Co.:** Winter (Nov-Mar) 7.77 c/kwh. Summer 2.98 c/kwh.	Judy White, PUC, (907) 276-6222
ARIZONA Corporation Commission, Utilities Division	Rates in effect for producers of no more than 100 kw. QFs eligible for the rates offered can choose either negotiated capacity payment or a 10 percent additive to the offered energy rate (for firm power capacity).	For producers of no more than 100 kw, before firm capacity additive: **Arizona Public Service Co.:** Summer (May-Oct) peak 4.308 c/kwh, off-peak 2.280 c/kwh. Winter peak 4.051 c/kwh, off-peak 2.494 c/kwh. **Tucson Electric Power Co.:** Summer (May-Oct) 4.4 c/kwh. Winter 3.5 c/kwh.	Fred Young, ACC, (602) 255-3000
ARKANSAS Public Service Commission	Rates set for QFs 100 kw and smaller; larger QFs may use these figures or negotiate. Currently no contracts for QFs over 100 kw. QFs are unlikely to succeed in negotiating capacity credits except perhaps for latter part of very long-term contracts.	**Arkansas Power & Light Co.:** Rate depends on voltage—lowest for transmission, highest for secondary. Summer peak 3.404-3.6 c/kwh, off-peak 3.056-3.229 c/kwh. Other months peak 2.959-3.121 c/kwh, off-peak 2.613-2.767. Rates for energy may drop if AP&L must pay any part of Grand Gulf nuclear plant. If capacity is sold off, rates could increase fairly rapidly. **Oklahoma Gas & Electric Co.:** Rates set so far for wind QFs 3.152 c/kwh & hydro QFs 4.885 c/kwh.	Karen Fricke (rules) & Donna Campbell (rates), PSC, (501) 371-2054.
BONNEVILLE POWER ADMINISTRATION (serves several Northwestern states)	Billing credit policy issued in final form. Minimal buyback credit, without capacity component, paid only to BPA's own direct customers until BPA's capacity, power surplus is diminished—roughly 1987). Policy encourages cogenerator to sell to own service-area utility.	See listings for individual states and utilities.	BPA, (503) 230-3002
CALIFORNIA Public Utilities Commission	Standard contract offerings on file for each utility. PUC requires projects to progress and to meet certain "milestones" within prescribed time period once power purchase agreement w/utility is signed. Projects of 50 Mw or more must apply for permit w/California Energy Commission (CEC). The CEC has up to one year to review an application once it is accepted. Selective catalytic reduction for nitrous oxide emissions is required on gas-fired cogeneration projects in areas that are not in compliance w/federal air quality standards.	Standard current offerings: **Pacific Gas & Electric Co.:** Energy on-peak 6.423 c/kwh; mid-peak 6.0 c/kwh; off-peak, 4.978 c/kwh. Weighted average 5.551 c/kwh. Capacity $60 per kw/year for 1-year contract; $135 per kw/year for 30-year contract. **Southern California Edison Co.:** Energy on-peak 6.1 c/kwh; mid-peak 4.7 c/kwh; off-peak 4.0 c/kwh. Weighted average 4.6 c/kwh. Capacity $63 per kw/year for 1-year contract; $135 per kw/year for 30-year contract. **San Diego Gas & Electric Co.:** For cogenerators under 100 kw, non-time-of-use payment: 6.98 c/kwh on-peak; 5.78 c/kwh mid-peak; 5.15 c/kwh off-peak. Capacity payments: $34 per kw/year for 1-year contracts; $95 per kw/year for 30-year contracts. Optional "as available" capacity payment for non-firm power: 2.07 c/kwh on-peak; .21 c/kwh mid-peak, none for off-peak.	Supervisor, Alternative Generation Section, PUC, (415) 557-1159
COLORADO Public Utilities Commission	PUC requires utilities to file avoided energy and capacity costs yearly (Dec.). Public Service began moratorium on its rate offering after an 80 Mw peak period—only cogenerator came on line on standard contract—a capacity boom not anticipated in the 1985 rates; utility is already capacity-long. Univ. of Northern Colo., a 63-Mw cogenerator, now protesting Public Service's refusal to negotiate. PUC hopes to settle it before 1986, in investigations 1603 & 1604.	For QFs 25 Mw and smaller. Larger QFs negotiate. **Public Service Co. of Colorado:** net energy billing for QFs under 5 kw (credited against retail, averaging 4.5 c/kwh). For QFs 5-300 kw: energy 1.567 c/kwh; capacity $20.11/kw/month for 15-year contract/longer; lower capacity credit for shorter contracts (e.g., 10% for 1 year, 50% for 5 year); capacity based on average kw each month. For QFs over 300 kw to 25 Mw, same as 5-300 kw QFs, but requires 70% capacity factor on peak & shoulder hours; rate drops proportionally for lower capacity factor. Negotiated rates almost exclusively match rates for 25 Mw QFs.	Michael Homyak (rules), PUC, (303) 866-4300; Arnelle Sebastian (rates), PUC, (303) 877-4283.
CONNECTICUT Department of Public Utility Control	DPUC is now involved in proceedings to revise the rules. An attorney for cogenerators said avoided cost payments are apt to rise, with higher energy payments and some provision for capacity payment. (Present rules do not require capacity credit.) Also, standard-offer contract terms likely to be shorter than the 30 years utilities must now offer. DPUC is expected to announce new rules & rates by 1986.	Current rates are from 89% to 117% of full avoided energy charge (adjusted monthly). Rates below largely reflect 1984 energy costs. **Connecticut Light & Power Co.:** avoided energy is 4.3-4.9 c/kwh with these multipliers: firm peak 117%, off-peak 92%; non-firm peak 114%, off-peak 89%. **United Illuminating Co.:** avoided energy is 4.6-5.4 c/kwh with these multipliers: firm peak 117%, off-peak 103%; non-firm peak 100%, off-peak 95%. Actual negotiated rates, based on 30-year contracts signed in 1985: 8 c/kwh minimum energy credit, escalating when utility costs exceed 8 cents, for a resource recovery plant; for a large cogenerator, energy payment equals published firm power rate, capacity rate is 3 c/kwh from 1985-1990, 1.75 c/kwh from 1990-2005.	Robert Pulito, DPUC, (203) 827-1553

STATES' COGENERATION RATE-SETTING UNDER PURPA, Part 2

(Part 1 appeared Sept. 9; Part 3 will appear Sept. 23)

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), state regulatory agencies were required to implement mechanisms to ensure that cogenerators receive (among other things) just, reasonable and non-discriminatory rates for electricity sold to electric utilities. To encourage cogeneration, these "buyback" rates were to be equal to the costs a utility saves by not having to generate or buy elsewhere the power it obtains from a cogenerator. The chief avoided cost components of buyback rates are the energy (fuel) credit and the capacity (construction) credit. Planning and calculating the capacity credit is a varied and often controversial process, and the rules are subject to change.

The status of states' PURPA cogeneration proceedings and cogeneration buyback rates for most major utilities is listed below. Information was supplied by state utility commissions, utilities and the law firm Chadbourne, Parke, Whiteside & Wolff, N.Y.

"QF" (qualifying facility) refers to cogenerators and other small power producers under PURPA. QFs are generally responsible for the cost of interconnection with the utility; the chart omits these fees and those for "administration." Some utilities also set special backup power rates for QFs who have the right to backup power under PURPA. Where standard offerings do not apply and the utility and cogenerator agree on rates and terms, the commission can arbitrate. In many cases, small-QF standard offerings act as negotiating bases for larger-QF contracts. Rates below do not necessarily apply to systems for which construction began before Nov. 9, 1978.

STATE	STATUS & RULES	RATES	CONTACT
DELAWARE Public Service Commission Wilmington, Del.	Standard offering for units of 1 Mw or less; capacity component not offered (attainable by negotiation only). Larger units negotiate with utility, PSC. No systems over 1 Mw on line in state. Cogenerators must install equipment correcting power factor to no less than 90 percent lagging.	Delmarva Power & Light Co.: Summer (June-Sept.) peak 4.82 c/kwh; off-peak 2.5 c/kwh (8 p.m.-8 a.m.). Winter peak 3.79 c/kwh; off-peak 2.6 c/kwh.	Leon Ryan, PSC, (302) 736-[illegible].
DISTRICT OF COLUMBIA Public Service Commission	Rates for units no larger than 100 kw include avoided capacity payments based on present value of utility's need for capacity in 1991. To qualify for capacity credit under standard offering, cogenerators must be on line for at least one year; must sign contract for at least two years; and must agree not to schedule maintenance during summer peak period. For QFs 100 kw or smaller, rates are set annually (not levelized) and are likely to rise with inflation during the contract. Levelized rate available for larger units. For all negotiated contracts, standard rate offerings serve as starting point.	Offerings for QFs no larger than 100 kw. Potomac Electric Power Co.: Energy component: summer (June-Sept) peak 5.942 c/kwh, intermediate 4.780 c/kwh, off-peak 2.[illegible] c/kwh; winter peak 4.23 c/kwh, intermediate, 3.725 c/kwh, off peak 2.[illegible] c/kwh. Year-round capacity payment: 1.783 c/kwh for contract of 8 years or less; 3.083 c/kwh for 17-year contract. Proposed Rates: Energy component: summer peak 6.313 c/kwh, intermediate 5.284 c/kwh, off-peak 3.007 c/kwh; winter peak 4.220 c/kwh, intermediate 3.631 c/kwh, off-peak 2.377 c/kwh. Year-round capacity payment: 1.586 c/kwh for contract of 7 years or less; 5.2 c/kwh for 15-year contract.	Economics Dept., PSC, (202) 727-3064.
FLORIDA Public Service Commission	Rates on file for QFs of any size (though larger ones may be able to negotiate better deals). Any size QF is eligible for the maximum capacity credit paid—80% of avoided cost (one statewide rate applies)—by entering contract at least 10 years long with 70% capacity factor. The capacity payment is expected to drop in Dec. Cogenerators' state Supreme Court case to secure 100% avoided capacity cost was withdrawn for unrelated reasons. With bond, partially levelized rates for capacity payments are available before 1992, when the first unit of additional capacity construction can be avoided (based on a hypothetical coal plant). On Sept. 3, the PSC issued a decision on wheeling and retail sales of cogenerated electricity, requiring such action and sales on a case-by-case basis only when neither would raise rates to the utility's other customers. Negotiated payments for capacity are very close to the statewide offering. Gulf Power will only be able to avoid a unit of additional capacity starting in 2002, and published its own tariff without a capacity credit; however, PSC told Gulf to sell unneeded power to other utilities. In negotiations, Florida Power and Tampa provide capacity payments lower than the state average. FP&L has the highest energy payments now available and above-average negotiated capacity payments.	(Winter is Oct-Mar; summer Apr-Sept) Florida Power Corp.: Energy: winter 1985-86 peak 3.43 c/kwh, off-peak 2.[illegible] c/kwh; summer 1986 peak 3.[illegible] c/kwh, off-peak 2.[illegible] c/kwh; winter 1986-87 peak 3.323 c/kwh, off-peak 2.[illegible] c/kwh; summer 1987 peak 4.349 c/kwh, off-peak 3.073 c/kwh. Florida Power & Light Co.: Energy: winter 1985-86 peak 3.[illegible] c/kwh, off-peak 3.511 c/kwh; summer 1986 peak 4.370 c/kwh, off-peak 3.[illegible] c/kwh; winter 1986-87 peak 4.110 c/kwh, off-peak 3.[illegible] c/kwh; summer 1987 peak 4.190 c/kwh, off-peak 3.[illegible] c/kwh. Gulf Power Co.: Energy: winter 1985-86 peak 2.[illegible] c/kwh, off-peak 2.[illegible] c/kwh; summer 1986 peak 2.[illegible] c/kwh, off-peak 2.[illegible] c/kwh; winter 1986-87 peak 2.[illegible] c/kwh, off-peak 2.416 c/kwh; summer 1987 peak 3.147, off-peak 2.[illegible] c/kwh. Tampa Electric Co.: Energy: winter 1985-86 peak 2.[illegible] c/kwh, off-peak 2.215 c/kwh; summer 1986 peak 3.[illegible] c/kwh, off-peak 2.[illegible] c/kwh; winter 1986-87 peak 2.816 c/kwh, off-peak 2.[illegible] c/kwh; summer 1987 peak 3.276 c/kwh, off-peak 2.[illegible] c/kwh. All utilities: To be adjusted for line losses depending on delivery voltage. Utilities offer all-hours rates as well as time-of-day rates. Levelized estimated energy component is 4.21 c/kwh in 1992, rising to 8.21 c/kwh in 2002. Capacity is added, either (1) $10.[illegible]/kw/month in 1992 for contracts then 20 years old, rising to $[illegible]/kw/month in 2002; or (2) $4.25/kw/month in 1985, rising (also at 5.4% per year) to $17.[illegible]/kw/month.	Bonnie Davis (rules), PSC, (904) 487-2740; Stan Hvostik (rates), PSC, (904) 488-[illegible].
GEORGIA Public Service Commission	Rules require no capacity credits. Georgia Power is in an extensive construction program, and capacity payments are negotiable only for units that will avoid additional capacity in 1996. Savannah (not building extensively) stated it would negotiate capacity credits at some agreed-upon capacity factor.	Georgia Power Co.: Fuel cost recovery rate for units under 100 kw 1.9-2.2 c/kwh. Estimated avoided energy cost for all other QFs: June-Sept peak 3.[illegible] c/kwh, off-peak 2.[illegible] c/kwh; all other periods 2.37 c/kwh. Savannah Electric & Power Co.: Fuel cost recovery rate for units under 100 kw 2.46 c/kwh. Estimated avoided energy cost for QFs up to 25 Mw: summer peak 4.000 c/kwh, all other times 2.725 c/kwh; for units 25-[illegible] Mw: summer peak 3.876 c/kwh, all other times 2.[illegible] c/kwh. Although 1984 estimates will be in effect until 1985, actual fuel rates paid during the past year averaged 2.70 c/kwh for those over 100 kw.	Sam Weaver, PSC, (404) [illegible].
HAWAII Public Utilities Commission	No capacity credit included in standard rates & none likely until 1991. PUC eliminated an earlier rule that held pre-PURPA QFs to only 70% of avoided cost. Capacity credits, long-term rates by negotiation only. New rule bars long-term contract rate from dropping below the starting point. Utility must petition PUC for negotiating assistance if no contract reached within 90 days of QF contact.	Standard for QFs under 100 kw. Base rate is the weighted average of on- and off-peak. Hawaiian Electric Co.: 6.6 c/net kwh (after any buy/sell). Hawaiian Electric Light Co.: 6.[illegible] c/net kwh. Maui Electric Co.: 6.[illegible] c/net kwh; 11.3 c/net kwh on Lanai. Kauai Electric (Citizens Utilities): 8.[illegible] c/net kwh.	Norman Lee, PUC, (808) 548-[illegible].
IDAHO Public Utilities Commission	Rates subject to periodic review by PUC.	Hearings pending for IPC, UP&L, and PP&L; rates due to decline slightly. Washington Water Power Co.: 35-year contract long-term levelized rate 4.4 c/kwh (includes capacity credit). Idaho Power Co.: Long-term interim rate pending outcome of current rate case: 4.3 c/kwh. PUC expected to approve staff recommendation of 5.3 c/kwh this fall. Utah Power and Light: 5.3 c/kwh with capacity credits; 1.3 c/kwh plus $117/kw/year for 4-year contract, $[illegible]/kw/year for 3-year contract and $[illegible]/kw/year for 35-year contract. Pacific Power and Light: 30-year contract: energy: peak 6.12 c/kwh, off-peak 4.[illegible] c/kwh; capacity $5.72/kw/month.	Bob Smith, director of rates and engineering, PUC, (208) 334-[illegible].

STATES' COGENERATION RATE-SETTING UNDER PURPA, Part 3

(Part 2 appeared Sept. [illegible]. Part 4 will appear Sept. 20)

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), state regulatory agencies were required to implement mechanisms to ensure that cogenerators receive (among other things) just, reasonable and non-discriminatory rates for electricity sold to electric utilities. To encourage cogeneration, these "buyback" rates were to be equal to the costs a utility saves by not having to generate or buy elsewhere the power it obtains from a cogenerator. The chief avoided cost components of buyback rates are the energy (fuel) credit and the capacity (construction) credit. Planning and calculating the capacity credit is a varied and often controversial process, and the rules are subject to change.

The status of states' PURPA cogeneration proceedings and cogeneration buyback rates for most major utilities is listed below. Information was supplied by state utility commissions, utilities and the law firm Chadbourne, Parke, Whiteside & Wolff, N.Y.

"QF" (qualifying facility) refers to cogenerators and other small power producers under PURPA. QFs are generally responsible for the cost of interconnection with the utility; the chart omits those fees and those for "administration." Some utilities also set special backup power rates for QFs who have the right to backup power under PURPA. Where standard offerings do not apply and the utility and cogenerator agree on rates and terms, the commission can arbitrate. In many cases, small-QF standard offerings act as negotiating bases for larger-QF contracts. Rates below do not necessarily apply to systems for which construction began before Nov. 9, 1978.

STATE	STATUS & RULES	RATES	CONTACT
ILLINOIS Illinois Commerce Commission	All terms and conditions for capacity credits subject to negotiation; no pre-set rules in effect. Energy rates change annually following a June 30 filing. Governor is expected to sign a bill that would prohibit utilities from discriminating against cogenerators when providing backup power. Chairman of ICC favors mandatory wheeling of cogenerated power; however, consensus of other commissioners and staff is that the ICC does not have authority to require wheeling; no resolution of issue expected soon. Negotiated rates are roughly the same as the standard filings.	**Commonwealth Edison Co.**: Units under 1 Mw: summer (mid June-mid Sept) peak 5.17 c/kwh, off-peak 2.30 c/kwh; other peak 5.06 c/kwh, off-peak 2.36 c/kwh. Units at least 1 Mw summer peak 5.17 c/kwh, off-peak 2.09 c/kwh; other peak 5.34 c/kwh, off-peak 2.28 c/kwh. **Central Illinois Light Co.**: Rates vary with voltage—sub-transmission is lowest, secondary is highest. Summer (Jun-Sept) peak 2.52-2.76 c/kwh, off-peak 2.22-2.38 c/kwh; other months peak 2.55-2.60 c/kwh, off-peak 2.22-2.38 c/kwh. **Central Illinois Public Service Co.**: Standard for QFs under 100 kw. Summer (Jun-Aug) peak 2.340 c/kwh, off-peak 2.127 c/kwh; other peak 2.303 c/kwh, off-peak 2.136 c/kwh. Non-time-of-day tariffs: summer 2.343 c/kwh, other 2.247 c/kwh. **Illinois Power Co.**: Rates vary with voltage; 2.4 kv at high rate, 138 kv at low rate. Summer (mid June-mid Sept) peak 2.38-2.65 c/kwh, off-peak 2.45-2.50 c/kwh. Other times 2.40-2.54 c/kwh.	Roy Buxton (general), ICC, (217) 785-5414; ICC clerk (rates), (217) 782-7434.
INDIANA Public Service Commission	PSC implemented revised rules in March, but these are currently under appeal by several utilities. Utilities protest a provision requiring them to pay capacity credits regardless of their construction schedules. This provision could raise the buyback rate from its current range of 0.81-4.17 c/kwh to a range of 2.8-7.4 c/kwh, according to PSC calculations. Utilities are also appealing mandatory wheeling of QF power under the new rules. PSC is now reviewing utilities' revised payback rate schedules, which include the capacity credit. Final approval is several months away.	**Public Service Co. of Indiana**: 1.623 c/kwh. Proposed: 1.713 c/kwh plus $2.86/kw/month for capacity. **Northern Indiana Public Service Co.**: Time-of-day: winter (Oct-Apr) peak 4.40 c/kwh, off-peak 3.86 c/kwh; summer peak 3.93 c/kwh, off-peak 3.47 c/kwh. Non-time-of-day: winter 4.13 c/kwh, summer 4.72 c/kwh. Proposed Energy: winter peak 3.125 c/kwh, off-peak 2.897 c/kwh; summer peak 2.980 c/kwh, off-peak 2.317 c/kwh. Proposed Capacity $3.20/kw/month. **Indiana & Michigan Electric Co.**: Time-of-day peak 1.36 c/kwh; off-peak and non-time-of-day rate 0.81 c/kwh. Proposed Energy: time-of-day peak 1.89 c/kwh; off-peak and non-time-of-day rate 1.67 c/kwh. Proposed Capacity $2.87/kw/month. **Indianapolis Power & Light Co.**: Unlimited power 1.51 c/kwh. No more than 72,000 kwh/month: winter (Nov-Apr) peak 1.90 c/kwh, off-peak 1.34 c/kwh; summer peak 1.78 c/kwh, off-peak 1.31 c/kwh. Proposed Energy 1.73 c/kwh. Proposed Capacity $3.07/kw/month. **Southern Indiana Gas & Electric Co.**: First 72,000 kwh/month: winter (Nov-Apr) peak 1.56 c/kwh, off-peak 1.30 c/kwh; summer peak 1.47 c/kwh, off-peak 1.19 c/kwh. In excess of 72,000 kwh/month: winter peak, 1.46 c/kwh, off-peak 1.26 c/kwh; summer peak 1.37 c/kwh, off-peak 1.27 c/kwh. Proposed Energy 1.734 c/kwh. Proposed Capacity $2.18/kw/month. **Richmond Power & Light Co.**: 0.814 c/kwh. Proposed demand rate $15.76/kw; proposed energy rate 1.884 c/kwh.	Lebron Pilalis (for rules), PSC, (317) 232-2700; Engineering Dept. (for rates), PSC, (317) 232-2736.
IOWA State Commerce Commission	Buyback rates for QFs under 100 kw include capacity credit for peak-period, delivered kwh based on utility's cost of borrowing power from the Mid-Continent Area Power Pool. Larger QFs negotiate. Wheeling of cogenerators' power mandated by SCC on a case-by-case basis.	For QFs under 100 kw: **Iowa Public Service Co.**: Time-of-day peak 2.08 c/kwh, off-peak 1.82 c/kwh. Non-time-of-day 1.96 c/kwh. **Iowa-Illinois Gas & Electric Co.**: Time-of-day: summer peak 2.55 c/kwh, off-peak 1.37 c/kwh; winter peak 2.09 c/kwh, off-peak 1.29 c/kwh. Non-time-of-day: summer 1.98 c/kwh, winter 1.63 c/kwh. **Iowa Power & Light Co.**: Time-of-day peak 1.45 c/kwh, off-peak 1.0 c/kwh. Non-time-of-day 1.05 c/kwh. **Iowa Electric Light & Power Co.**: Energy: summer peak 2.5 c/kwh; winter peak 2.3 c/kwh; year-round off peak 1.4 c/kwh.	Art Zahler, Utilities Div., SCC, (515) 281-5547.
KANSAS Kansas Corporation Commission	Rates on file for QFs under 100 kw. Larger QFs (& small QFs seeking capacity credit) negotiate. No capacity credits now paid to QFs under 100 kw, but larger QFs may have negotiated some. (Kansas Supreme Court last year struck down KCC rate formula that included capacity credits, saying they exceeded actual avoided cost). KCC is considering making rules on wheeling.	For QFs under 100 kw. QFs may choose time-differentiated rates or all-hours rates. **Kansas Gas & Electric Co.**: Last 6 months average 2.027 c/kwh. In Oct., rates expected to drop to about 1.124 c/kwh. **Kansas City Power & Light Co.**: Last 6 months average 1.61 c/kwh. In Oct., rates expected to drop to 1.06 c/kwh. Annual average expected to be between 1.4 and 1.45 c/kwh. **Kansas Power & Light Co.**: Last 5 months average 1.706 c/kwh. Expected to remain stable. All utilities: since capacity credits are rare, these energy rates are a good indication of large QFs' negotiated rates.	Eva Powers (rules), KCC, (913) 296-2543; Ron Ford (rates), KCC, (913) 296-2067.
KENTUCKY Public Service Commission	Under rules, utilities judge whether to offer capacity credits; only Kentucky Power does. PSC will consider each utility's plans for incorporating cogeneration and small power production into capacity planning in each utility's next base rate case; if no capacity credit is offered, utility must prove that is correct (Union Light case now pending). PSC will also question avoided energy rates. State's only QF now uses power on-site.	Any QF may sign up for these rates, or negotiate. **Kentucky Utilities Co.**: 2.5 c/kwh. **Louisville Gas & Electric Co.**: 1.96 c/kwh. **Kentucky Power Co.**: Energy: peak 1.46 c/kwh; off-peak & non-time-of-day 1.02 c/kwh. Capacity (contract at least 2 years): peak $3/kw/month; off-peak or non-time-of-day $1.50/kw/month. **Union Light, Heat & Power Co.**: 1985 peak 2.3067 c/kwh, off-peak 1.7496 c/kwh. 1986 peak 2.3679 c/kwh, off-peak 1.8260 c/kwh. May change in October.	Jim Sharpe, PSC, (502) 564-8119.

STATES' COGENERATION RATE-SETTING UNDER PURPA, Part 4

(Part 3 appeared Sept. 23; Part 5 will appear Oct. 7)

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), state regulatory agencies were required to implement mechanisms to ensure that cogenerators receive (among other things) just, reasonable and non-discriminatory rates for electricity sold to electric utilities. To encourage cogeneration, these "buyback" rates were to be equal to the costs a utility saves by not having to generate or buy elsewhere the power it obtains from a cogenerator. The chief avoided cost components of buyback rates are the energy (fuel) credit and the capacity (construction) credit. Planning and calculating the capacity credit is a varied and often controversial process, and the rules are subject to change.

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"QF" (qualifying facility) refers to cogenerators and other small power producers under PURPA. QFs are generally responsible for the cost of interconnection with the utility; the chart omits these fees and those for "administration." Some utilities also set special backup power rates for QFs who have the right to backup power under PURPA. Where standard offerings do not apply and the utility and cogenerator agree on rates and terms, the commission can arbitrate. In many cases, small-QF standard offerings act as negotiating bases for larger-QF contracts. Rates below do not necessarily apply to systems for which construction began before Nov. 9, 1978.

STATE	STATUS & RULES	RATES	CONTACT
LOUISIANA Public Service Commission	Rates set for QF's 100 kw and under. Larger QFs (and smaller QF's seeking capacity payments) negotiate. No avoided capacity payments foreseen until mid-1980s.	**Louisiana Power & Light Co.:** 1985 avoided cost: summer peak 3.179 c/kwh, off-peak 2.378 c/kwh; winter peak 3.353 c/kwh, off-peak 2.403 c/kwh. Expected to rise slightly in 1986. QFs 100 kw and under are paid avoided cost. **Gulf States Utilities Co.:** 1985 avoided cost: summer peak 4.983 c/kwh, off-peak 4.334 c/kwh; winter peak 4.683 c/kwh, off-peak 4.380 c/kwh. Expected to fall slightly in 1986. Rates for QFs under 100 kw are negotiated. **Southwestern Electric Power Co.:** 1985 avoided cost: third-quarter 2.163 c/kwh, fourth quarter 1.880 c/kwh. Estimates for 1986: first quarter 3.553 c/kwh, second quarter 4.457 c/kwh, third quarter 4.409 c/kwh, fourth quarter 3.711 c/kwh. Rates for QFs 100 kw and smaller are currently above avoided cost, with seasonal, time-of-day rates ranging from 2.1791 to 3.5151 c/kwh. **Central Louisiana Electric Co.:** 1985 avoided cost 3.0 c/kwh. Buyback rate for QFs 100 kw and smaller 2.8 c/kwh. Avoided cost expected to rise to 3.1 c/kwh in 1986. **New Orleans Public Service Inc.:** Regulated by New Orleans City Council. Avoided energy costs for QFs 100 kw and under: winter 1985 average 3.063 c/kwh; summer 1985 average 3.73 c/kwh. QFs over 100 kw are paid either the actual cost at the hour it is avoided or a negotiated long-term rate. The current fuel adjustment amount, a very rough index of avoided cost, is 1.9-2.5 c/kwh; expected to stay low for several years.	Arnold Chauviere, (504) 342-1403, & Robert Crowe, (504) 342-1413, both PSC. Nelson Daigle, NOPSI, (504) 363-6708.
MAINE Public Utilities Commission	Rules set cumulative energy and capacity rates (levelized; minimum contract 5 years), which generally decrease as the utility buys more blocks of power—"decrements"—50 Mw for CMP, 20 Mw for Bangor. CMP QF's bid under the set rate for contracts. QFs up to 100 kw are credited at retail rate against own bill (net energy billing).	Generally applicable to any-size QF **Central Maine Power Co.:** Based on 15-year contract, QF's any size 6.8 c/kwh (fourth decrement). Lower rates are expected to be set for a fifth decrement later this year to last through 1986. QFs bid for contracts, & rates are typically 85-100% of this total avoided cost. Retail rate credited to QFs using more than they buy or under 5-year contract 4.6 c/kwh. **Bangor Hydroelectric Co.:** Based on 15-year contract, now 7.0 c/kwh, but a fourth decrement price is to be set in the next few months, probably at 6.8 c/kwh or slightly less. Negotiated prices are generally 85-100% of this total avoided cost. Short-term or small QF energy only rate: averages around 4.3-4.9 c/kwh.	Charley Jacobs, Norman Leonard, PUC, (207) 289-3831.
MARYLAND Public Service Commission	Rules implemented on a per-utility basis. Standard rate offerings for cogenerators of 1 Mw or less set annually. Status of capacity payments is in flux: only BG&E has an approved capacity calculation method. Potomac Edison and Delmarva have been ordered to file capacity payment formulas. PSC now studying Potomac Electric Power (PEPCO) proposal. QF's above 1 Mw negotiate with utilities subject to PSC approval. Rates are levelized, and in general negotiated rates are no greater than standard rates in present value terms.	**Baltimore Gas & Electric Co.:** Energy: summer (June-Sept) peak 4.795 c/kwh, intermediate 3.315 c/kwh, off-peak 1.740 c/kwh; winter peak & intermediate 3.565 c/kwh, off-peak 1.830 c/kwh. Capacity: under a 15-year contract $2.53/kw/year (adjusted yearly for inflation); to qualify QF must exceed 100 kwh, meet 5 percent peak capacity factor (for full payment), enter minimum 15-year contract, post performance bond. Capacity payment is fixed unless contract renegotiated or utility's capacity requirement changes. Amount will be expressed in real dollars over contract life. **Delmarva Power & Light Co.:** Summer (June-Sept) peak 3.04 c/kwh, off-peak 2.07 c/kwh. Winter peak 3.24 c/kwh, off-peak 2.36 c/kwh. **Potomac Electric Power Co. (PEPCO):** Summer (June-Sept) peak 6.313 c/kwh, intermediate 5.364 c/kwh, off-peak 3.097 c/kwh. Winter peak 4.239 c/kwh, intermediate 3.631 c/kwh, off-peak 2.377 c/kwh. Proposed capacity payment formula based on linear programming model forecasting avoided energy and capacity costs for 18-year period. PEPCO proposed that QFs of 100 kw or less enter into 15-year contract. In 1985, payment would be 4.751 c/kwh during summer peak only. QFs larger than 100 kw would negotiate for avoided capac[illegible] rates. PEPCO actual negotiated rates for a Jan. 1985 contract: Summer, 1985: 5.383 c/kwh peak, 4.651 c/kwh intermediate, 2.677 c/kwh off-peak. Winter, 1985: 4.190 c/kwh peak, 3.800 c/kwh intermediate, 2.412 c/kwh off-peak. By the year 2000 energy payments will be: Summer: 10.432 c/kwh peak, 9.010 c/kwh intermediate, 5.500 c/kwh off-peak. Winter: 8.299 c/kwh peak, 6.833 c/kwh intermediate, 3.628 c/kwh off-peak. Avoided capacity payments start at 5.510 c/kwh in 1991 (for summer peak kwh only) and escalate to 7.611 c/kwh by the year 2000. All rates are in 1984 constant dollars, and will be adjusted annually for inflation. **Potomac Edison Co.:** peak 1.780 c/kwh, off-peak 1.285 c/kwh.	Doug Kinney, PSC, (301) 659-6022.
MASSACHUSETTS Department of Public Utilities	At the request of the Executive Office of Energy Resources, the DPU is undertaking a comprehensive review of PURPA. A recent interim order has been issued requesting comment on the terms and conditions for standard offer contracts and long-term rates. Currently, utilities are not required to enter into long-term contracts, although some have. Another issue to be discussed is wheeling; presently, utilities are not required to wheel for QF's. Hearings and opportunity for comment will be Oct. 9 and 10 at 100 Cambridge St., Boston, 12th floor. Utilities are required to offer cogenerators financing terms for up to three years for interconnection costs.	All rates listed for secondary voltage. **Boston Edison (through October 1985):** 5.517 c/kwh peak, 3.380 c/kwh off-peak, 4.280 c/kwh flat average. **Commonwealth Electric (through September 1985):** 4.261 c/kwh peak, 3.747 c/kwh off-peak, 3.985 c/kwh flat average. **Massachusetts Electric (through September 1985):** 4.91 c/kwh peak, 3.08 c/kwh off-peak, 3.94 c/kwh flat average. **Western Massachusetts Electric (through November 1985):** 4.078 c/kwh peak, 4.164 c/kwh off-peak, 4.252 c/kwh flat average.	Catherine Morris, Director Electric Power Division, DPU, (617) 727-9748.

STATES' COGENERATION RATE-SETTING UNDER PURPA, Part 5

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), state regulatory agencies were required to implement mechanisms to ensure that cogenerators receive (among other things) just, reasonable and non-discriminatory rates for electricity sold to electric utilities. To encourage cogeneration, these "buyback" rates were to be equal to the costs a utility saves by not having to generate or buy elsewhere the power it obtains from a cogenerator. The chief avoided cost components of buyback rates are the energy (fuel) credit and the capacity (construction) credit. Planning and calculating the capacity credit is a varied and often controversial process, and the rules are subject to change.

The status of states' PURPA cogeneration proceedings and cogeneration buyback rates for most major utilities is listed below. Information was supplied by state utility commissions, utilities and the law firm Chadbourne, Parke, Whiteside & Wolff, N.Y.

"QF" (qualifying facility) refers to cogenerators and other small power producers under PURPA. QF's are generally responsible for the cost of interconnection with the utility; the chart omits these fees and those for "administration." Some utilities also set special backup power rates for QF's who have the right to backup power under PURPA. Where standard offerings do not apply and the utility and cogenerator agree on rates and terms, the commission can arbitrate. In many cases, small-QF standard offerings act as negotiating bases for larger-QF contracts. Rates below do not necessarily apply to systems for which construction began before Nov. 9, 1978.

STATE	STATUS & RULES	RATES	CONTACT
MICHIGAN Public Service Commission	Capacity credit offered on sliding scale for contracts of 1 to 35 years, the tariff increasing with the length of contract. Actual range varies among utilities. Levelized capacity payments have been used since 1982. PSC currently rethinking the practice. No timetable for a decision has been set. PSC not supportive of wheeling cogenerated power into Michigan from other states; believes any rulemaking ordering wheeling within the state would also allow interstate wheeling.	Generally for all units, standard under 100 kw. Consumers Power Co.: 2.72 c/kwh, fixed 35-year-contract capacity credit 3.76 c/kwh. Detroit Edison Co.: 2.60 c/kwh, fixed 35-year contract capacity credit 3.27 c/kwh. Actual contracts tend to be: energy 3.5 c/kwh plus fixed 35-year-contract capacity 3.5 c/kwh. Wisconsin Electric Power: same rates as in Wisconsin; must offer capacity credit.	Donald Johns, PSC, (517) 373-8171
MINNESOTA Public Service Commission	Final rules adopted Nov. 1984 set buyback for units under 40 kw at retail rate, require utilities to conform to a statewide uniform contract for QF's under 100 kw. Capacity credit offered to units with a 60% on-peak capacity factor. Informal PSC hearings currently under way to set standard rates for units in the 1-5 Mw range and guidelines for negotiation for even larger units. Hearings expected to end in late Oct. Capacity credits are levelized; energy credits change with annual filings by utilities. Wheeling is mandatory upon cogenerator's request.	Accurate for both small and large units. Northern States Power Co.: "Net energy billing" for QFS no larger than 40 kw: retail rate winter (Oct-May) 5.38 c/kwh, summer 6.04 c/kwh; for QF sales in excess of purchase: winter 2.0 c/kwh & summer 1.91 c/kwh, plus capacity credit 0.62 c/kwh winter & 1.04 c/kwh summer. QF's no more than 100 kw and firm power QFs any size: Energy: winter peak 2.35 c/kwh, summer peak 2.22 c/kwh, all-year off-peak 1.185 c/kwh. Capacity: 1.77 c/kwh winter, 3.60 c/kwh summer. Minnesota Power & Light Co.: QF's under 40 kw net energy billing general-customer-size 5.91 c/kwh, large class customer 4.58 c/kwh; for QF sales in excess of purchase: 1.35 c/kwh. Time-of-day option, and units 40-100 kw: peak 1.38 c/kwh, off-peak 1.32 c/kwh. Otter Tail Power Co.: For QF's no larger than 40 kw. General retail service energy 1.610 c/kwh, non-energy 4.06 c/kwh. Large general retail service energy 1.610 c/kwh, non-energy 2.086 c/kwh.	Stuart Mitchell (for rules), PSC, (612) 296-8862; Karen Santori (for rates), Dept of Public Service, (612) 296-[illegible]
MISSISSIPPI Public Service Commission	Capacity credits are not required; currently none are paid. Rates different from standard filings can be negotiated at any time.	Mississippi Power & Light Co.: Avoided energy costs currently 3 to 3.5 c/kwh. Because Grand Gulf nuclear power plant recently came on line, rates are not expected to go over 4 c/kwh for several years. Mississippi Power Co.: Avoided energy costs currently 2.5 to 3 c/kwh. Rates expected to rise slightly in near future. Anticipated rates 1986: summer peak 3.7 c/kwh, off-peak 2.98 c/kwh; winter all-hours 2.61 c/kwh. Anticipated rates 1987: summer peak 3.69 c/kwh, off-peak 2.9 c/kwh; winter all-hours 2.81 c/kwh. Anticipated rates 1988: summer peak 3.86 c/kwh, off-peak 3.12 c/kwh; winter all-hours 3.21 c/kwh.	Hugh Stevens, PSC, (601) 961-5464
MISSOURI Public Service Commission	Rates filed only for QF's under 100 kw. Larger QF's negotiate; rates depend on size of QF and length of contract. Capacity payments by negotiation only. Utilities are required to wheel QF power within the state.	Average energy credits for QFs under 100 kw: Kansas City Power & Light Co.: 1.86 c/kwh. Utility will update the rate in Oct or Nov. Union Electric Co.: Time-of-day: summer peak 2.66 c/kwh, off-peak 1.61 c/kwh; weekends & holidays 1.67 c/kwh; winter peak 1.89 c/kwh, off-peak 1.63 c/kwh, weekends & holidays 1.62 c/kwh. Non-time-of-day: summer 2.05 c/kwh; winter 1.72 c/kwh. Missouri Public Service Co.: 2.107 c/kwh. Empire District Electric Co.: Summer 2.67 c/kwh. Winter 2.21 c/kwh. All utilities: energy credits for larger QFs are similar to these, with capacity credits added on top.	Jim Ketter, PSC, (314) 751-2314
MONTANA Public Service Commission	Energy & capacity credits paid to all QFs under contracts of 4 to 35 years, either fully or partially levelized, or escalating. Capacity-payments listed are for QFs with power available 85 percent of the time; payments for QFs at other capacity factors are directly proportional. PSC has opened a rate methodology docket (84.10.64) considering rate changes to attract more QF power.	New contracts under these standard offerings are subject to PSC adjustments depending on outcome of Docket 84.10.64. Montana Power Co.: Fully levelized: 4-year 4.344 c/kwh plus $66.82/kw/year; 35-year 6.280 c/kwh plus $97.80/kw/year. Partially levelized: 4-year begins at 4.082 c/kwh plus $66.71, both escalating yearly; 35-year begins at 5.443 c/kwh plus $97.17, both escalating yearly. Escalating begins at 3.797 c/kwh plus $80.74 c/kwh. Montana-Dakota Utilities Co. Fully levelized: 4-year 4.137 c/kwh plus $45.12/kw/year; 35-year 5.752 c/kwh plus $82.65/kw/year. Partially levelized: 4-year begins at 3.956 c/kwh plus $44.80/kw/year, both escalating yearly. Escalating begins at 3.680 c/kwh plus $40.15/kw/year. Pacific Power & Light Co.: Fully levelized: 4-year 3.866 c/kwh plus $5.70/kw/month; 35-year 6.556 c/kwh plus $8.84/kw/month. Partially levelized: 4-year begins at 3.644 c/kwh plus $5.60/kw/month, both escalating yearly; 35-year begins at 5.628 c/kwh plus $8.41/kw/month, both escalating yearly. Escalating begins at 3.380 c/kwh plus $4.96/kw/month.	Michael Lee, PSC, (406) 444-6180
NEBRASKA	Virtually every town in Nebraska has its own electric utility, and there is no central state regulatory body to oversee them. Annual forecasts and assessments of power supply options are filed with the Nebraska Power Association's Power Review Board. Rates are approved by local governing bodies.	Currently no capacity payments and no long-term contracts are offered in Nebraska. Avoided energy costs paid to QF's are now 1.5-2 c/kwh. Because the rates are low there is little cogeneration. No QF's are selling power to the major utilities—Omaha Public Power District, Lincoln Electric System, Nebraska Public Power District, Nebraska Municipal Power Pool and Tri-State Generation & Power.	Skip Laitner, Nebraska Energy Office, (402) 471-3715 (for general information) and individual utilities.

STATES' COGENERATION RATE-SETTING UNDER PURPA, Part 6

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), state regulatory agencies were required to implement mechanisms to ensure that cogenerators receive (among other things) just, reasonable and non-discriminatory rates for electricity sold to electric utilities. To encourage cogeneration, these "buyback" rates were to be equal to the costs a utility saves by not having to generate or buy elsewhere the power it obtains from a cogenerator. The chief avoided cost components of buyback rates are the energy (fuel) credit and the capacity (construction) credit. Planning and calculating the capacity credit is a varied and often controversial process, and the rules are subject to change.

The status of states' PURPA cogeneration proceedings and cogeneration buyback rates for most major utilities is listed below. Information was supplied by state utility commissions, utilities and the law firm Chadbourne, Parke, Whiteside & Wolff, N.Y.

"QF" (qualifying facility) refers to cogenerators and other small power producers under PURPA. QFs are generally responsible for the cost of interconnection with the utility; the chart omits these fees and those for "administration." Some utilities also set special backup power rates for QFs who have the right to backup power under PURPA. Where standard offerings do not apply and the utility and cogenerator agree on rates and terms, the commission can arbitrate. In many cases, small-QF standard offerings act as negotiating bases for larger-QF contracts. Rates below do not necessarily apply to systems for which construction began before Nov. 9, 1978.

STATE	STATUS & RULES	RATES	CONTACT
NEVADA **Public Service Commission**	Both utilities have recently filed updated short-term rates, long-term rates for first-time and standard contracts with the PSC. PSC is now reviewing these rates for implementation in 1986. PSC expected to address rate methodology, qualification for capacity credit, levelized rates, performance bond requirements.	Standard for QFs within 100 kw, subject to adjustment as often as 4 times yearly. **Sierra Pacific Power Co.**: Energy 5.1 c/kwh. Capacity 0.82 c/kwh based on lowest sellback of previous 11 months. **Nevada Power Co.**: Energy: summer (June-Sept) peak 4.752 c/kwh, off-peak 3.287; winter (Nov-Apr) peak 3.328, off-peak 2.894; May & Oct peak 3.757, off-peak 2.561. Capacity: summer peak $8.73/kw/month, off-peak 3 c/kw/month; winter peak $2.38/kw/month, off-peak 20 c/kw/month; May & Oct peak 46c/kw/month, off-peak 1c/kw/month.	Ronald F. Helbling, PSC, (702) 885-5408.
NEW HAMPSHIRE **Public Utilities Commission**	PSC-NH audit to determine proper capacity credit for eligible QFs (larger than 15 kw). Standard rates applicable to any cogenerator, though some can negotiate. (Note: as of present, most QFs are taking rates rather than negotiating because of PSC-NH's financial situation regarding Seabrook; negotiated contracts seem risky). Small retail utilities for whom PSC is the major buyer have agreed to wheel for PSC.	**Public Service Co. of N.H.**: For units larger than 15 kw. Short term: (energy rates change Jan. and July) peak 5.79 c/kwh, off-peak 4.28 c/kwh, all hours 4.94 c/kwh, capacity $42.08/kw/year. Levelized long-term rates: all hours 1986 start, 10-year 5.73 c/kwh plus $35.73/kw/year, 20-year 7.76 c/kwh plus $85.87/kw/year; 30-year 9.80 c/kwh plus $86.22/kw/year. All hours 1987 start, 10-year 6.1 c/kwh plus $38.12/kw/year; 20-year 8.36/kwh plus $81.62/kw/year; 30-year 10.62/kwh plus $102.67/kw/year. **Granite State Electric Co. (New England Elec. System)**: short-term primary, (no capacity) peak 5.749 c/kwh, off-peak 3.837/kwh, all hours 4.79 c/kwh; adjusted January and July. **Connecticut Valley Electric Co.**: short-term (capacity rolled in) 7.8 c/kwh.	Sarah Voll, PUC, (603) 271-3431.
NEW JERSEY **Board of Public Utilities**	Energy payments set monthly at 110% of the rate utilities pay for power from Pennsylvania-New Jersey-Maryland (PJM) power pool. Capacity payments set in each base rate request, also linked to PJM rates. Rates designed for cogenerators of 1 Mw or less. Only QFs 100 kw or larger qualify for capacity payments. QFs over 1 Mw negotiate with utility, need BPU approval. To date, majority of negotiated contracts have tracked standard rates. Several contracts now under negotiation may be levelized at BPU encouragement. Standby power costs roughly 15% of standard industrial demand tariff. BPU, with utilities, now in process of formulating wheeling rules & rate methodology; FERC expected to approve rates by 1986. BPU also currently working on methodology for Jersey Central capacity payments to better reflect Three Mile Island shutdown.	**Public Service Gas & Electric Co.**: (latest available May 1985) peak 5.53 c/kwh, intermediate 4.36 c/kwh, off-peak 2.73 c/kwh. **Jersey Central Power & Light**: (latest available May 1985) peak 5.38 c/kwh, off-peak 3.95 c/kwh. **Atlantic City Electric Co.**: (latest available June 1985) all hours 3.5 c/kwh. **All utilities**: generic capacity rate $4.41/kw/month. Cogenerators must meet routine reliability test to qualify. In effect until July 1985.	Bob Chilton, BPU, (201) 648-6963.
NEW MEXICO **Public Service Commission**	Standard rates on file for QFs 100 kw and under. QFs any size may always negotiate too. All capacity credits are negotiated, although a task force is meeting to decide whether they should be made mandatory even though there is a capacity surplus in the state. Major changes expected in early 1986 after task force makes its recommendations, but it is impossible to predict their direction. A task force is also meeting to consider setting wheeling rules. There are few if any QFs over 100 kw in N. Mex.	**Public Service Co. of New Mexico**: Primary voltage is lower, secondary is higher of each pair of figures. Summer peak 4.080-5.344 c/kwh, off-peak 2.996-3.236; or all-hours 3.483-3.675. Other months peak 4.90-5.348, off-peak 4.084-4.237 c/kwh; or all-hours 3.837-4.084 c/kwh. **Texas-New Mexico Power Co.**: Option of 3.472 c/kwh plus fuel factor (0.4 c/kwh) or avoided cost contract. **Southwestern Public Service Co.**: Average cost of fuel (0.184 c/kwh) plus average of purchased power (2.65 c/kwh). **El Paso Electric Co.**: Average cost of fuel (0.583 c/kwh) times heat rate (3.7) plus 0.05 c/kwh; or 3 c/kwh, whichever is higher. **Plains Electric Generation & Transmission Co.**: Energy credit of 2.836 c/kwh plus fuel adjustment (0.814 c/kwh).	Prasad Potturi, rules, (505) 827-6940, & Tom Halpin, rates, (505) 827-7067 (both PSC).
NEW YORK **Public Service Commission**	PSC rules set 6 c/kwh as a statewide minimum average time-of-day rate. Capacity figured using peaker unit approach as marginal generating costs. Presently, QFs can negotiate contracts for the minimum rate or for existing avoided cost rates, whichever is higher, with a reconciliation procedure to determine the actual levels as contract proceeds. PSC is currently doing a 20-year forecast on Niagara Mohawk rates that should lead to standardized figures for statewide long-term contracts without reconciliation procedures. Results are expected by the end of the year. Utilities need not provide financing plans for QFs' interconnect fees. Special backup demand and supplementary rates are offered to QFs. The PSC has the authority to order a utility to wheel, but the issue has never been tested.	Figures are from the latest tariffs available; rate change at every rate case. **Consolidated Edison**: Standard for units over 500 kw (incorporates capacity credit), secondary voltage level: summer peak 10.21 c/kwh, off-peak 4.77 c/kwh; winter peak 8.37 c/kwh, off-peak 4.37 c/kwh. **Niagara Mohawk Power**: (includes capacity credit) secondary voltage level: peak 7.172 c/kwh, off-peak 3.648 c/kwh; primary voltage: peak 6.934 c/kwh, off-peak 3.517 c/kwh; transmission level: peak 5.213 c/kwh, off-peak 3.377 c/kwh. **Orange & Rockland Utilities**: (includes capacity credit) Summer peak: 7.8 c/kwh secondary, 7.497/kwh primary; summer off-peak: 4.088 c/kwh secondary, 3.894 c/kwh primary; winter peak: 4.996 c/kwh secondary, 4.768 c/kwh primary; winter off-peak: 3.089 c/kwh secondary, 3.906 c/kwh primary. **Central Hudson Gas & Electric**: (includes capacity payments). First to third in each trio of figures: secondary voltage, primary voltage, transmission voltage. Summer peak: 8.189-7.644-6.098 c/kwh. Winter peak: 6.974-6.483-6.088 c/kwh. Spring and fall peak: 6.330-5.882-5.512 c/kwh. All year peak: 4.587-4.281-4.111 c/kwh. Fuel cost adjustments are added. **New York State Gas & Electric**: Approximate with time of day and seasonal variations. Transmission level: peak 4.19 c/kwh, off-peak 2.29 c/kwh; Sub-transmission level: peak 4.22 c/kwh, off-peak 2.36 c/kwh; primary level: peak 4.77 c/kwh, off-peak 2.63 c/kwh; Secondary level: peak 4.72 c/kwh, off-peak 2.50c/kwh. **Rochester Gas & Electric Corp**: (over 300 kw) First to third in each trio of figures: secondary voltage, primary voltage, transmission voltage. Summer peak: 4.954-5.264-4.884 c/kwh. Summer off-peak: 3.807-3.858-2.882 c/kwh. Winter peak: 4.996-5.243-4.911 c/kwh. Winter off-peak: 3.134-3.220-3.080 c/kwh. All-year peak: 4.797-5.088-4.820 c/kwh. All-year off-peak: 3.080-3.963-3.718 c/kwh.	Frank Berak, PSC, (518) 474-1372.

STATES' COGENERATION RATE-SETTING UNDER PURPA, Part 7

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), state regulatory agencies were required to implement mechanisms to ensure that cogenerators receive (among other things) just, reasonable and non-discriminatory rates for electricity sold to electric utilities. To encourage cogeneration, these "buyback" rates were to be equal to the costs a utility saves by not having to generate or buy elsewhere the power it obtains from a cogenerator. The chief avoided cost components of buyback rates are the energy (fuel) credit and the capacity (construction) credit. Planning and calculating the capacity credit is a varied and often controversial process, and the rules are subject to change.

The status of states' PURPA cogeneration proceedings and cogeneration buyback rates for most major utilities is listed below. Information was supplied by state utility commissions, utilities and the law firm Chadbourne, Parke, Whiteside & Wolff, N.Y.

"QF" (qualifying facility) refers to cogenerators and other small power producers under PURPA. QFs are generally responsible for the cost of interconnection with the utility; the chart omits these fees and those for "administration." Some utilities also set special backup power rates for QFs who have the right to backup power under PURPA. Where standard offerings do not apply and the utility and cogenerator agree on rates and terms, the commission can arbitrate. In many cases, small-QF standard offerings act as negotiating bases for larger-QF contracts. Rates below do not necessarily apply to systems for which construction began before Nov. 9, 1978.

STATE	STATUS & RULES	RATES	CONTACT
NORTH CAROLINA Utilities Commission	NCUC has found it appropriate to credit peak capacity, which is included in all standard rates. Utilities must also consider capacity credits for QFs not on standard rates. Standard long-term, levelized contract rates are available to QFs 5 Mw and smaller (100 kw and smaller for Virginia E&P); NCUC expects larger QFs have the expertise to negotiate. Filed rates are reviewed biennially (these finalized Feb. 1).	QF may choose variable/short-term, 5-year, 10-year or 15-year contract (not all listed). **Carolina Power & Light Co.:** Short-term: peak 3.404 c/kwh, off-peak 2.8 c/kwh, plus summer (Apr-Sept) peak capacity 1.440 c/kwh, winter peak capacity 1.220 c/kwh. Fixed 5-year contract: peak 3.900 c/kwh, off-peak 3.2 c/kwh; plus summer peak capacity 1.607 c/kwh, winter peak capacity 1.320 c/kwh. Fixed 15-year contract: peak 5.513 c/kwh, off-peak 4.374 c/kwh; plus summer peak capacity 1.644 c/kwh, winter peak capacity 1.413 c/kwh. (Peak hours are 10 a.m.-10 p.m. Mon-Fri in summer; 6 a.m.-1 p.m. & 4 p.m.-9 p.m. in winter.) **Duke Power Co.:** Short-term: peak hours 2.90 c/kwh, off-peak hours 2.16 c/kwh; plus peak-hours capacity 1.50 c/kwh in peak months (June-Sept & Dec-Mar), 0.80 c/kwh in other months. Fixed 5-year contract: peak hours 3.13 c/kwh, off-peak 2.36 c/kwh; plus peak-hours capacity 1.61 c/kwh in peak months, 0.86 c/kwh in off-peak months. Fixed 15-year contract: peak hours 4.18 c/kwh, off-peak hours 3.19 c/kwh; plus peak-hours capacity 1.96 c/kwh in peak months, 1.17 c/kwh in off-peak months. (Peak hours are 7 a.m.-11 p.m. Mon.-Fri.) **Virginia Electric & Power Co.:** (Standard for QF's no larger than 100 kw.) Short term: peak 4.023 c/kwh, off-peak 2.676 c/kwh; plus peak capacity 0.804 c/kwh. Fixed 15-year contract: peak 6.362 c/kwh, off-peak 3.781 c/kwh; plus peak capacity 1.242 c/kwh.	Tim Carrere, NCUC, (919) 733-2267.
NORTH DAKOTA Public Service Commission	Capacity credits vary in proportion to length of contract, from 5 to 35 years; 65% capacity factor required. Rates approved for QF's under 100 kw. Larger QF's negotiate. Non-firm rates per kwh incorporate capacity credit; firm rates list it separately. Rates change only following rate cases or in instances where utility expenses change drastically.	**Montana-Dakota Utilities Co.:** Non-firm peak 2.21 c/kwh, off-peak 1.57 c/kwh; or all-hours 1.81 c/kwh. Firm dependable energy 0.95 c/kwh plus capacity credit based on length of contract (5-35 years), from 1.97 to 3.08 c/kwh. **Northern States Power Co.:** Non-firm peak 2.15 c/kwh, off-peak 1.39 c/kwh; or all hours 1.66 c/kwh. Firm dependable energy 1.35 c/kwh plus capacity credit based on length of contract, (5-35 years), from 0.71 to 1.72 c/kwh. **Otter Tail Power Co.:** Non-firm summer peak 1.11 c/kwh, off-peak 0.86 c/kwh; winter peak 1.97 c/kwh, off-peak 1.31 c/kwh; or all-year, all-hours 1.35 c/kwh. Firm dependable energy 1.14 c/kwh plus capacity credit based on length of contract (5-35 years), from 1.08 to 2.21 c/kwh.	Steven Kahl, PSC, (701) 224-4075.
OHIO Public Utilities Commission of Ohio	Tariffs approved for units within 100 kw, varying slightly with utilities' fuel costs. Units over 100 kw negotiate with utility and obtain PUCO approval. PUCO does not require utilities to pay avoided capacity for QFs of 100 kw or less, but 5 of 8 do offer credits, calculated according to varying methodologies. Capacity payments generally run 2-5 c/kwh. To qualify for such payments, QFs typically need to enter into contracts of 10-20 years. Rates generally are levelized with PUCO encouragement. Some utilities provide capacity credits for on-peak power only. PUCO is expected to announce a generic backup power tariff within next 6 months.	For units of 100 kw or less: **Cincinnati Gas & Electric Co.:** peak 2.0784 c/kwh, off-peak 1.850 c/kwh. **Cleveland Electric Illuminating Co.:** summer peak 2.9 c/kwh, off-peak 2.3 c/kwh; winter peak 3.0 c/kwh, off-peak 2.3 c/kwh. **Columbus & Southern Ohio Gas & Electric Co.:** peak 1.68 c/kwh, off-peak 1.41 c/kwh. **Dayton Power & Light Co.:** peak 3.52 c/kwh, off-peak 2.27 c/kwh. **Monongahela Power Co.:** summer peak 1.570 c/kwh, off-peak 1.34 c/kwh; winter peak 2.90 c/kwh, off-peak 1.66 c/kwh; spring & fall peak 3.05 c/kwh, off-peak 1.71 c/kwh. **Ohio Edison Co.:** peak 2.34 c/kwh, off-peak 1.70 c/kwh.	John Georgiadis, PUCO, (614) 466-6049.
OKLAHOMA Public Service Commission	Rates filed for non-cogenerator QFs under 100 kw only. Each utility will calculate a rate when one is requested. Rates for larger QFs (including capacity credits, if any) are negotiated but must be approved by the OCC. Rules let OCC adjust contract rates & terms later, for instance if utility avoided cost changes. Fuel costs fluctuate over contract life.	**Oklahoma Gas & Electric Co.:** QFs under 100 kw 2.382 c/kwh wind, 3.308 c/kwh hydro. OG&E currently buys power from a 3.2 Mw cogenerator, at an energy credit of 2.7 c/kwh plus a conservation incentive surcharge of 1.5 c/kwh, which the OCC approved because the QF burns solid waste. (Customers in Okla. City, where the plant is, pay the extra cost.) The OCC has directed OG&E to offer the same deal to other solid waste cogenerators. **Public Service Co. of Oklahoma:** QFs under 100 kw. Wind: summer (June-Sept) 4.126 c/kwh, winter 2.460 c/kwh. Hydro: summer 5.314 c/kwh, winter 3.656 c/kwh (reflect higher-than-normal fuel costs). By contract, utility pays a 10 Mw cogenerator about 4 c/kwh, energy only. Another contract pays a small power producer 4-4.5 c/kwh, including an indeterminate capacity credit and reflecting 1982 fuel costs; actual rate will be higher when it comes on line in 1986. **Both utilities:** Rates should remain fairly stable for at least 5-10 years.	Larry Schroeder, OCC, (405) 521-2335.
OREGON Public Utility Commission	Buyback rates revised annually.	**Pacific Power & Light Co.:** 20-year contract, starts in 1986 at a rate of 2.07 c/kwh, rises to 9.57 cents in 2005. 30-year contract begins in 1986 at 2.29 c/kwh, rises to 19.05 cents in 2015. Short-term standard contract for projects up to 100 kw: Nov-April: 1.92 c/kwh; May-Oct: 1.79 cents. **Portland General Electric Co.:** 20-year contract beginning in 1986 at 2.1 c/kwh, rising to 10.27 cents in 2005. 30-year contract begins in 1986 at 2.1 c/kwh, rises to 15.82 cents in 2015. Short-term standard contract for projects up to 100 kw: Nov-April: 3.00 c/kwh; May-Oct: 2.46 c/kwh.	Lynn Kittilson, PUC utility cost analyst, (503) 373-1000.

STATES' COGENERATION RATE-SETTING UNDER PURPA, Part 8

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), state regulatory agencies were required to implement mechanisms to ensure that cogenerators receive (among other things) just, reasonable and non-discriminatory rates for electricity sold to electric utilities. To encourage cogeneration, these "buyback" rates were to be equal to the costs a utility saves by not having to generate or buy elsewhere the power it obtains from a cogenerator. The chief avoided cost components of buyback rates are the energy (fuel) credit and the capacity (construction) credit. Planning and calculating the capacity credit is a varied and often controversial process, and the rules are subject to change.

The status of states' PURPA cogeneration proceedings and cogeneration buyback rates for most major utilities is listed below. Information was supplied by state utility commissions, utilities and the law firm Chadbourne, Parke, Whiteside & Wolff, N.Y.

"QF" (qualifying facility) refers to cogenerators and other small power producers under PURPA. QF's are generally responsible for the cost of interconnection with the utility; the chart omits these fees and those for "administration." Some utilities also set special backup power rates for QF's who have the right to backup power under PURPA. Where standard offerings do not apply and the utility and cogenerator agree on rates and terms, the commission can arbitrate. In many cases, small-QF standard offerings act as negotiating bases for larger-QF contracts. Rates below do not necessarily apply to systems for which construction began before Nov. 9, 1978.

STATE	STATUS & RULES	RATES	CONTACT
PENNSYLVANIA Public Utility Commission	Standard rates in effect for QF's of 500 kw and less provide for energy and capacity payments. Avoided capacity based on utility's 10-year load forecast and revised annually. QF's currently have option of taking energy payments or reduced energy payments with avoided capacity. Standard rates are levelized over 10-year period. Cogenerators larger than 500 kw negotiate with utilities and can use standardized rates as starting point. Most negotiated contracts to date based on PJM billing rate with pre-agreed escalators built in over life of agreement. QF's must agree to 10-year contracts in order to receive avoided capacity payments. Utilities must provide backup power at standard service rates. PUC has made no rulings on wheeling. Four of seven major utilities—Duquesne Light Co., Philadelphia Electric Co., Pennsylvania Power Co., and West Penn Power Co.—have objected to state's rules on avoided capacity and currently offer no such payments. Negotiations between commission and companies are continuing.	(Standard rates for QF's of 500 kw and less levelized over 10-year period. QF's can opt to select among a number of avoided capacity payment plans. Payments change annually.) Pennsylvania Electric Co: all hours 4.62 c/kwh. Metropolitan Edison Co.: all hours 4.89 c/kwh. Pennsylvania Power & Light Co.: all hours 5.11 c/kwh, 6 c/kwh for QF's employing renewable energy sources in cogeneration. Philadelphia Electric Co.: all hours 4.39 c/kwh. West Penn Power Co.: all hours 2.2 c/kwh. Duquesne Light Co.: all hours 2.33 c/kwh. Pennsylvania Power Co.: all hours 1.80 c/kwh.	Tyrone Christy, PUC (717) 783-8476
RHODE ISLAND Public Utilities Commission	Suggest contracts be made without PUC involvement; PUC will help resolve disputes. No capacity credits required. No rules for wheeling, but utilities are required to do so.	Avoided energy costs in 1985: Narragansett Electric Co.: (July) peak 4.3c/kwh; off-peak 3.0 c/kwh; or all- hours 3.6 c/kwh. Blackstone Valley Electric Co.: (July) primary voltage on-peak 4.9c/kwh; off-peak 3.4c/kwh; all-hours 4.0c/kwh. Secondary voltage on-peak 5.2c/kwh; off-peak 3.5c/kwh; all-hours 4.2 c/kwh. Newport Electric Co.: (July) on-peak 3.9c/kwh; off-peak 3.2 c/kwh; all-hours 3.6 c/kwh. PUC reports that for 20-year plus contracts, utilities are now negotiating rates closer to 7 or 8 cents per kwh. Interconnect fees split 50-50 between each utility and smaller power producer.	Doug Hartley, PUC, (401) 277-3500
SOUTH CAROLINA Public Service Commission	On PSC order, all 3 utilities have proposed slightly revised energy rates, and Duke has proposed new capacity rates. Order required Duke to offer capacity credit per peak kwh all year rather than credits in 6 peak months based on lowest capacity during month. SCE&G not required to offer capacity credit since it has 400 Mw plant excess on which it collects no rates; PSC to review that finding in mid-1986. Long-term rates not mandatory. PSC may order intrastate wheeling that does not use interstate transmission grid, if that is possible anywhere.	PSC apt to approve proposed energy rates with minimal or no adjustment. Carolina Power & Light Co.: Standard for QFs 5 Mw & under. Proposed energy: peak 4.12 c/kwh, off-peak 2.985 c/kwh. Capacity (peak kwh): summer (June-Sept) 1.442 c/kwh; non-summer 1.338 c/kwh. One large cogenerator has negotiated a rate of 1.2 to 1.4 c/kwh for peak capacity 1987-90, and 5.00 c/kwh 1991-2006. Peak energy begins at 3.9 c/kwh in 1987, rises to 5.2 c/kwh in 1990, falls to 3.7 c/kwh for 1991, rises to 8.26 c/kwh in 2001. Off-peak energy about 1 cent less than peak through 1990, equals peak rate 1991-2001. South Carolina Electric & Gas Co.: Standard for QFs 100 kw and under. Proposed energy: summer (June-Sept) peak 2.750 c/kwh, off-peak 2.184 c/kwh; winter peak 2.731 c/kwh, off-peak 2.584 c/kwh. Large QF's negotiated rate is the same as proposed rate. Duke Power Co.: Standard for QFs 80 Mw & under. Proposed energy: peak 3.13 c/kwh, off-peak 2.32 c/kwh. Current capacity $5.80/kw/peak month. Proposed capacity (peak hours) 1.17 c/kwh.	Bill Sheely, PSC, (803) 758-5262.
SOUTH DAKOTA Public Utilities Commission	Standard tariffs and permanent rules approved Jan. 1985. Capacity credits offered only by Montana-Dakota and Otter Tail, which have small service areas in the state. Utilities have filed special rates for standby power to cogenerators.	For QFs under 100 kw; good negotiating benchmarks for larger units. Black Hills Power & Light Co.: 1.8 c/kwh Northern States Power Co.: peak 2.10 c/kwh, off-peak 1.36 c/kwh; or all-hours 1.62 c/kwh. Northwestern Public Service Co.: 1.75 c/kwh. Montana-Dakota Power Co.: Energy: summer peak 2.160 c/kwh, off-peak 1.881 c/kwh; winter peak 2.314 c/kwh, off-peak 1.669 c/kwh; or occasional sales up to 600,000 kwh/month 2.022 c/kwh. Capacity (85% peak capacity factor required): contracts under 10 years $2.90/kw/month; longer contracts $12.90/kw/month. Otter Tail Power Co.: Energy: summer peak 2.03 c/kwh, off-peak 1.46 c/kwh; winter peak 2.30 c/kwh, off-peak 1.73 c/kwh; or occasional sales 1.67 c/kwh. Capacity (80% capacity factor required) depends on contract length: 5-year $7.72/kw/month (5 years) to $13.82/kw/month (25 years).	Martin Bettmann, PUC, (605) 773-3201.
TENNESSEE Public Service Commission	No rules or rates in effect. The PSC regulates only one small electric utility—Kingsport. Several years ago Kingsport filed a QF rate proposal, which is still pending and probably dated. The TVA (next week) and its distribution utilities serve most of Tenn.	Kingsport Power Co.: None yet, but Kingsport buys all its power from sister utility Appalachian Power Co. at roughly 3.5 c/kwh, averaged over all hours. These purchase rates would affect buyback rates.	Richard Bibb, PsC, (615) 741-2791; Kingsport, (615) 246-3115.

STATES' COGENERATION RATE-SETTING UNDER PURPA, Part 9

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), state regulatory agencies were required to implement mechanisms to ensure that cogenerators receive (among other things) just, reasonable and non-discriminatory rates for electricity sold to electric utilities. To encourage cogeneration, these "buyback" rates were to be equal to the costs a utility saves by not having to generate or buy elsewhere the power it obtains from a cogenerator. The chief avoided cost components of buyback rates are the energy (fuel) credit and the capacity (construction) credit. Planning and calculating the capacity credit is a varied and often controversial process, and the rules are subject to change.

The status of states' PURPA cogeneration proceedings and cogeneration buyback rates for most major utilities is listed below. Information was supplied by state utility commissions, utilities and the law firm Chadbourne, Parke, Whiteside & Wolff, N.Y.

"QF" (qualifying facility) refers to cogenerators and other small power producers under PURPA. QFs are generally responsible for the cost of interconnection with the utility; the chart omits these fees and those for "administration." Some utilities also set special backup power rates for QFs who have the right to backup power under PURPA. Where standard offerings do not apply and the utility and cogenerator agree on rates and terms, the commission can arbitrate. In many cases, small-QF standard offerings act as negotiating bases for larger-QF contracts. Rates below do not necessarily apply to systems for which construction began before Nov. 9, 1978.

STATE	STATUS & RULES	RATES	CONTACT
TENNESSEE VALLEY AUTHORITY (Serves users in 7 states)	TVA staff reported adjusted avoided cost figures for new QFs last month. No capacity credit on contracts under 10 years. TVA offers 3 standard rates to QFs 500 kw or smaller. Larger QFs may negotiate a fixed purchase price contract up to 20 years (not levelized); rate is guaranteed for half the contract term and then returns to the long term standard rate offering. Larger renewable energy QFs may negotiate a levelized contract up to 30 years, with rate guaranteed for two-thirds the contract term. TVA willing to negotiate wheeling.	Standard offerings (adjusted yearly, even during contract) for QFs selling power to any of TVA's 160 distribution utilities. New rates expected to rise little, if at all. Contracts under 10 years: peak 1.96 c/kwh, off-peak 1.68 c/kwh, or all-hours 1.91 c/kwh. Contracts at least 10 years (includes capacity credit): peak 2.53 c/kwh, off-peak 1.60 c/kwh. Staff estimates a 30-year contract for QFs coming on line now pays 3.5-4 c/kwh over the 30-year levelized period; expects rates may rise significantly in the later portion.	Sam Power & Harold Usher, cogeneration development, TVA, (615) 751-6781
TEXAS Public Utility Commission	Utilities required to file statements of capacity needs, avoided capacity costs, and capacity credit eligibility criteria; required to establish standard offer of maximum avoided cost for any QF; required to wheel power on cogenerator's request; wheeling tariff calculation methodology established. Settlement negotiations with the PUC on these figures are now in progress, and final amounts should be set by early 1986. Rates can always be negotiated, but if there is no competition for meeting the utility's calculated capacity shortfall, this ceiling amount must be paid. Standard tariffs are on file for QFs 100 kw and below. Avoided cost figures can be adjusted according to firmness.	Pending finalization of the filings outlined above, all major Texas investor-owned electric utilities, including Houston Lighting and Power, Gulf States Utilities, Texas Utilities Electric, and Central Power and Light, are paying approximately 3 cents per kwh for nonfirm power (energy credits only). In the majority of these cases, natural gas is the avoided fuel. Most utilities paying capacity credits are avoiding coal as a fuel; capacity payments run between $10 and $20 per kw per month, and energy payments are between 2 and 2.5 cents per kwh. These rates are not expected to change dramatically over the next year.	Kent Saathoff, PUC, (512) 458-0215
UTAH Public Service Commission	Standard form contracts available to facilitate power purchase agreements. Energy payment revised annually.	Average payments for units under 1 Mw: 2.1 c/kwh energy payment, 3.1 c/kwh capacity payment. Average total of 5.24 c/kwh.	Douglas Kirk, PSC staff technical director, (801) 530-5711
VERMONT Public Service Board	Rules cover projected marginal energy and capacity up to 30-year terms. Contracts available in 5-, 10-, and 15-year terms for non-firm power (non-levelized); 10-, 20-, and 30-year terms for firm power (levelized); one-year spot sales. Rates decrease as the Vermont Power Exchange buys more blocks of power (25 Mw decrements). Rates begin when power delivery commences, and are uniform statewide.	30-year firm, third decrement: capacity credit, 1.77 c/kwh; winter on-peak 14.10 c/kwh, off-peak 7.77 c/kwh; summer peak 8.15 c/kwh, off-peak 3.62 c/kwh; all hours, all months 10.05 c/kwh. 1-year spot sales third decrement: capacity credit .67 c/kwh, winter peak 5.97 c/kwh, off-peak 4.21 c/kwh; summer peak 3.14 c/kwh, off-peak 1.26 c/kwh; all hours, all months 4.27 c/kwh. If requested, utilities must lend cogenerators money to finance interconnect lines.	Carl Bartel, PSB, (802) 828-2405
VIRGINIA State Corporation Commission	Later this month, the SCC will vote on a Virginia Power Co. proposal to adopt current energy rates and new capacity rates that would favor longer-term contracts. The commission is also reviewing Appalachian Power Co. proposals to reduce its current capacity credits and increase its energy credits. SCC staff plans to recommend a higher peak capacity rate than Apco proposes. The SCC is expected to decide on the measures by December or January.	Standards for units 100 kw or lower; negotiated basis for larger units. To account for voltage line losses, actual contracts pay an average of 4 percent higher than the standard rate for electricity received by the utility. Negotiated rates are still higher for contracts that specify a high capacity factor. **Virginia Power Co.**: Energy peak 3.908 cents/kwh, off peak 2.304 c/kwh. Interim peak capacity: contracts under 5 years, 1.085 c/kwh; longer contracts 1.6 c/kwh. Proposed peak capacity: contracts up to 9 years 0.883 c/kwh; ranging up to 30-year terms at 2.227 c/kwh. **Appalachian Power Co.**: Energy: peak 1.88 c/kwh, proposed peak 1.92 c/kwh off-peak; off-peak 1.50 c/kwh, proposed off-peak 1.70 c/kwh; or all-hours 1.73 c/kwh, proposed all-hours 1.80 c/kwh. Capacity (2-year contract minimum): 2- to 8-year contracts standard $1.50/kw/month for current and proposed, or peak $3/kw/month, proposed $2/kw/month, plus off-peak $1.50/kw/month, proposed $1/kw/month; 9th year and beyond based on cost of new fossil plant capacity.	Eswara Raju, SCC, [illegible]
WASHINGTON Utilities & Transportation Commission	Capacity payments not provided for current year. WWP's buyback rate has two parts: a fixed rate and a rate that varies from year to year.	**Pacific Power & Light**: levelized long-term contracts: non-firm: 1.55 c/kwh in '85, rises to 1.95 c/kwh in '88; firm: 1.70 c/kwh in '85, rises to 2.10 c/kwh in '88 and 3.10 c/kwh in '93. Rate also available for projects under 100 kw: 3.466 c/kwh for the first 080 kwh delivered, 4.65 c/kwh for all subsequent kwh. Capacity payments beginning in '94 vary from $4.05/kw per month to $7.26 per kw per month, depending on length of contract. **Puget Sound Power & Light Co.**: April-Sept.: 1.22 c/kwh; Oct.-March: 1.60 c/kwh. **Washington Water Power Co.**: Levelized rate for 5-year contract: July-Oct.: 1.7 c/kwh; Nov-Feb.: 2.4 c/kwh; March-June: 1.2 c/kwh. Rate for 20-year contract: July-Oct.: 3.8 c/kwh; Nov.-Feb.: 5.4 c/kwh; March-June: 2.6 c/kwh. For 35-year contract: July-Oct.: 4.6 c/kwh; Nov-Feb.: 6.6 c/kwh; March-June: 3.2 c/kwh. Variable rate for '85 to '86: July-Oct.: 1.3 c/kwh; Nov.-Feb.: 1.9 c/kwh; March-June: .9 c/kwh.	James Levesque, UTC, (206) 753-2229

STATES' COGENERATION RATE-SETTING UNDER PURPA, Part 10

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), state regulatory agencies were required to implement mechanisms to ensure that cogenerators receive (among other things) just, reasonable and non-discriminatory rates for electricity sold to electric utilities. To encourage cogeneration, these "buyback" rates were to be equal to the costs a utility saves by not having to generate or buy elsewhere the power it obtains from a cogenerator. The chief avoided cost components of buyback rates are the energy (fuel) credit and the capacity (construction) credit. Planning and calculating the capacity credit is a varied and often controversial process, and the rules are subject to change.

The status of states' PURPA cogeneration proceedings and cogeneration buyback rates for most major utilities is listed below. Information was supplied by state utility commissions, utilities and the law firm Chadbourne, Parke, Whiteside & Wolff, N.Y.

"QF" (qualifying facility) refers to cogenerators and other small power producers under PURPA. QFs are generally responsible for the cost of interconnection with the utility; the chart omits these fees and those for "administration." Some utilities also set special backup power rates for QFs who have the right to backup power under PURPA. Where standard offerings do not apply and the utility and cogenerator agree on rates and terms, the commission can arbitrate. In many cases, small-QF standard offerings act as negotiating bases for larger-QF contracts. Rates below do not necessarily apply to systems for which construction began before Nov. 9, 1978.

STATE	STATUS & RULES	RATES	CONTACT
WEST VIRGINIA Public Service Commission	Standard rate offering for QFs 100 kw & smaller. Backup power is provided at rates equal to standard customer tariffs. Rates for QFs larger than 100 kw must be negotiated with PSC review; no large units now on line.	**Wheeling Electric Co.:** Energy: peak 1.75 c/kwh, off-peak & all-hours rate 1.48 c/kwh. Capacity: 2-8 year contract: $3/kw/month for peak capacity, $1.50/kw/month for off-peak/all-hours capacity. Rates after year 8 may be higher depending on system needs; estimated maximum capacity credit equals $3.51/kw/month. **Appalachian Power Co.:** same as Wheeling, but in contracts over 8 years, adjusted maximum capacity credits are estimated at $12.21 kw/month peak, off-peak $3.06/kw/month. **Monongahela Power Co.:** Energy peak 1.37 c/kwh, off-peak & all-hours 1.302 c/kwh. Capacity payments for 2-year contracts, on-peak kwh only 0.50 c/kwh; may be adjusted higher after year 8 depending on system needs. **Potomac Edison Co.:** same as Monongahela. **Virginia Electric & Power Co.:** Energy: peak 3.968 c/kwh, off-peak 2.304 c/kwh. Avoided capacity, peak hours only, for 1-9 year contract 0.833 c/kwh, escalating to 1.694 c/kwh for 30-year agreement.	PSC, (304) 348-2174.
WISCONSIN Public Service Commission	PSC currently considering requirement for levelized payments to cogenerators. Decision not expected until early 1986. Capacity credits included in energy rate. Energy rate will rise as costlier power is avoided. Capacity credits rise in proportion to capacity factor and size of unit. PSC has deemed rulemaking for wheeling of cogenerator's power unnecessary; but issue may arise in 1986. Some cogenerators argue that PSC does not have jurisdiction to rule on wheeling.	All rates likely to change within the next several months as all utilities listed below have announced intentions to file for rate hikes. No filings have yet occurred. QFs under 20 kw paid at retail rate. Standard offerings for units 20-100 kw; should be considered the negotiating floor for larger QFs. Peak hours rates include capacity credit. **Wisconsin Power and Light Co.:** First to third figures in trio are transmission, distribution and secondary voltage. 14-hour peak 4.13-4.30-4.45 c/kwh; off-peak 2.24-2.29-2.37 c/kwh. **Wisconsin Electric Power Co.:** High primary-secondary voltage: 13-hour peak 3.68-3.96-4.07 c/kwh; off-peak 2.10-2.30-2.38 c/kwh. Larger units currently recieving through negotiation levelized energy payments for up to 7 years and levelized capacity credits for longer periods. **Wisconsin Public Service Corp.:** Highest to lowest voltage 115/138 /-46/69 c/kwh: 16-hour peak 2.96-3.13 c/kwh; off-peak 2.20-2.22 c/kwh. **Northern States Power Co.** (includes Lake Superior District Power Co.): Transmission-primary-secondary voltage: 13-hour peak 4.04-4.14-4.28 c/kwh; off-peak 1.99-2.04-2.14 c/kwh. **Madison Gas and Electric:** Primary-secondary voltage: 11-hour peak 3.96-4.09 c/kwh, off-peak 2.34-2.39 c/kwh.	Wayne DeForest, PSC, Utility Rates Div., (608) [illegible].
WYOMING Public Service Commission	Cogenerator must prove it operates at utility peak to qualify for standard offerings, including capacity credit. Given overcapacity, a likely change in the avoided energy cost method and the age of these tariffs (June 1983), PSC expects new rate filings soon.	**Pacific Power & Light Co.:** Standard offering to all QFs: 1985 energy: peak 2.06 c/kwh, off-peak 1.37 c/kwh, all-hours 1.70 c/kwh. 1984 fixed energy: 4.17 c/kwh plus a variable portion, 2.08 c/kwh, which escalates at 6% yearly. Capacity, first offered in 1984, depends on contract term: 1 year remaining $4.06/kw/month; 10 years remaining $5.06/kw/month; 35 years remaining $7.36/kw/month. **Utah Power & Light Co.:** Energy 2.2 c/kwh. Energy plus qualifying peak capacity 2.6 c/kwh. **Cheyenne Light, Fuel & Power Co.:** Energy 2.329 c/kwh. Capacity [illegible]/kw/month.	Phil Lehr, PSC, (307) 777-7427.

The **Chairman**. Mr. Miller.

STATEMENT OF ALAN S. MILLER, ASSOCIATE, WORLD RESOURCES INSTITUTE

Mr. **Miller**. My name is Alan Miller. I am a lawyer with the World Resources Institute, which is a nonprofit policy research center here in Washington, that deals with a wide range of global resource problems.

I have participated in the evolution of PURPA virtually since its enactment, and upon being offered the opportunity to testify here, I went back and looked at the testimony that I first gave before a congressional oversight committee in April 1981. One of the things that surprised me was how little many of the issues have changed.

I want to simply note that much of what happened, however, was surprisingly well predicted, at that time, even in the earliest days, and in particular I think the case in the record over the last 2 days of hearings has demonstrated in some detail the benefits that have come about as predicted in 1978, by Congress, and subsequently at oversight hearings in the early 1980's.

The first point I would make is that our conclusion is that the PURPA concept is really not at issue here. As the Pfeffer Lindsay Report, released by DOE in late 1985, last year, concluded, many of the inefficiencies observed in this area are based on inappropriate computations on avoided costs, rather than the statutory concept of avoided costs.

That, I think, is a fair characterization of what many of the disagreements are about; that is, they have been references to methodological questions, difficulties in the evolution of what is after all correctly characterized as something of a revolution in the way utilities are regulated.

If there had been some rough edges in that process, you should not consider that a major failure in the act.

Indeed, the importance of the PURPA concept and the direction toward increased competition and private sector involvement, is something that has been of interest, not only in the United States, but increasingly worldwide.

The benefits of expanded resources, sharing of risks, increased reliability and flexibility and, further, the promotion of innovation, is something that is being explored now by the World Bank, by the Agency for International Development, and increasingly, by a number of developing countries for precisely the same reasons that we have pioneered in this area in the United States.

One problem in the discussion of PURPA may in fact really be primarily be semantical. People talk often of PURPA benefits, which is really a misleading phrase. PURPA creates a market that did not otherwise exist because of what had been monopoly benefits, one might say, conferred to utilities.

It is the creation of a level playing field and the opportunity for competition, rather than the notion of benefits or the opportunity for competition that should be our focus.

This competition has brought substantial benefits. I think some of those have been reviewed well by the representatives of the States who were here this morning. I would simply reiterate, with

Mr. Anderson, the importance of recognizing that full avoided costs are rarely paid, and that in some cases, State approaches have more rapidly moved toward declining avoided costs, particularly in the States of Massachusetts and Maine, who are unfortunately not represented here. In both cases, the adoption of declining decrements, which have moved rapidly toward adjustments in avoided costs, that may have reflected some of the difficulties and rigid computational approaches in the past.

I would also note that some of the issues about technology, choice, and fuel choice are really much more issues of market factors, rather than a reflection of anything inherent in the PURPA concept. After all, utilities as well as third-party investors are increasingly looking toward gas-fired combined cycle plants.

For example, the Midland Nuclear Plant, canceled by Consumers Power, is now being converted to a gas-fired plant. That is a decision that the utility has made and explains in some detail in the current issue of the Public Utilities Fortnightly.

Similarly, the local utility, Pepco, is looking for its next plant addition from a coal-gassified combined cycle plant, rather than from a larger baseload plant. That is the same technologies for the same reasons; smaller scale, modular and shorter leadtime are increasingly the preference of the utility industry as a market-led choice, as much as they can be attributed in any sense to PURPA.

If anything, there may be increasingly unjustified restrictions on utility use of natural gas that ought to be examined in the context of the Fuel Use Act, which the Senate has, in other hearings, been reviewing that are the problem and not PURPA, insofar as it has encouraged third-party investments in gas-fired projects.

As one other example of the benefits that have occurred from these alternative technologies, I would note that in the State of California, the cost of PURPA projects, on average to this time, has been roughly half that of the cost of Diablo Canyon. So that the bringing on line of those PURPA projects certainly in that case has been of enormous consumer benefit.

Further, as several speakers have also noted, the improved reliability of these projects through their diversity and small scale, the fact that one does not risk an outage of 1,000 megawatts from an individual, 50-megawatt cogeneration system is a significant improvement in utility planning that ought to be recognized as a substantial benefit to utility ratepayers.

One point that has not, I think, been recognized previously in this hearing is the importance of the incentives for innovation and risk taking that are created by PURPA. There is a tremendous revolution going on in technologies for generating electricity. Some of these were reviewed in a report last year by the Office of Technology Assessment on alternative electric generation technology.

But, having served on the advisory panel for that report, which was issued in July 1985, I am struck by how, in several areas, it is already remarkably outdated. For example, there has been in the evolution of gas turbine technology a remarkable series of developments in steam ejected gas turbines, proposals for intercooled steam ejected gas turbines, all of which are being driven in part by the expanded opportunity for sharing of risks and investment of third-party money.

This opportunity becomes even more important in the context of ongoing changes in the Tax Code and in Federal R&D policy which have otherwise greatly reduced the Federal role in support of innovative electric generating technologies. That is, PURPA may be the one important remaining Federal incentive for innovation in electric generation.

If I have any reservations about PURPA, it is that in two principal areas it does not go far enough. First, I would agree largely with the concept of Mr. Anderson, that the sharing of power and the expanded opportunity for wheeling is a major issue that simply was not addressed in detail by PURPA and that ought to be revisited.

One of the answers to the problem of excess supply and of the unique situation that Senator Evans referred to in the Northwest, where there may, in fact, be periods when there are even no avoided energy costs, is to wheel power, along the lines that have been discussed for expanded sharing between the Northwest and Southwest.

It is that greater power sharing and the greater opportunity for wheeling that will address some of that problem.

In addition, Senator Evans also referred to what I consider to be the other remaining missing link, and that has been the absence of equal terms for efficiency investments. It may not be possible through a PURPA-like approach, although some have been tried, for example, in the State of New Jersey on an experimental basis, where efficiency investments were undertaken through a bidding system, and PG&E has similarly investigated such an approach in a study released just 1 month ago, but the general concept has been explored thoroughly in the Northwest Power Plan and in several other State-lease cost planning exercises.

That general area of examination of efficiency is something that should also be kept in mind when looking at the long-run implications of PURPA and utility supply planning.

Finally, I just want to close by noting that I think some of the conversation, Senator McClure, in the last panel concerning the comparative risks of over- versus under-capacity is, in fact, very much at the heart of this hearing.

I think there is an inherent contradiction, to some extent, between the utility emphasis on what is increasingly the concern about long-run power supply, possible shortages in the mid-1990's, and on the other hand, an unwillingness to accept some short-term purchases to lock in QF's and to create a better climate for QF's that can help assure that we have a long run source of alternative supply.

I think that utility baseload generation has a role, but that QF's are increasingly playing an important role as part of assuring long-term adequacy of power supply.

Thank you.

[The prepared statement of Mr. Miller follows:]

PURPA OVERSIGHT

hearings before the
Senate Committee on Energy and Natural Resources
June 5, 1986

Statement of Alan S. Miller, Associate,
World Resources Institute,
Washington, D.C.

The Public Utility Regulatory Policies Act (PURPA) has achieved great success in creating a competitive market for the generation of electricity. The market response to PURPA shows that there are many demonstrated technologies that have shorter leader times and lower cost than conventional base load power plants. The PURPA approach is being studied with increasing interest in many parts of the world, particularly developing countries historically dependent on public sector financing for power projects.

Criticism of the PURPA concept appears to be ill-founded. There is considerable argument about the calculation of avoided costs which reflects both methodological ambiguities and utility disagreement with state support for independent power generation. PURPA has also promoted interest in some technologies that may be economically justified but controversial due to other public policy concerns, notably new dams and gas-fired cogeneration. However, the basic approach is sound.

Some confusion arises from statements that PURPA is a source of "benefits" for independent power producers, to the exclusion of utility ratepayers. PURPA does no more than provide independent power producers with the opportunity to compete with the cost of utility generated power. The average cost of PURPA projects has been far less than the cost of new nuclear plants and has held utility costs lower than they otherwise would have been. The risk that PURPA projects will not be brought on line or operated with high reliability is also not borne by consumers. The Maine and Massachusetts bidding systems also demonstrate that the PURPA concept can be used to lower costs to consumers.

Another unrecognized benefit of PURPA is that it is proving to be a spur to technological innovation that will promote lower costs and a wider range of alternative generating technologies. The costs of this innovation will be shared by private investors but will benefit all consumers. For example, small-scale advanced gas turbines are already much less expensive than conventional power plants, even using DOE gas price forecasts.

PURPA is deficient insofar as it does not extend to investments in improved energy efficiency that may cost far less than any supply technology. This need should be addressed at the federal and state levels through a mix of incentives and regulation, along the lines evolving in the Northwest Power Plan.

The CHAIRMAN. Thank you.
Mr. Ward.

STATEMENT OF DENNIS P. WARD, FINANCIAL COMMITTEE, ATOMIC INDUSTRIAL FORUM

Mr. WARD. Thank you, Mr. Chairman. I am Dennis Ward, associate and head of the environmental division of Sargent & Lundy. I am appearing before you today representing the Financial Committee of the Atomic Industrial Forum, which is a trade association with over 500 members.

My testimony today is going to focus on the real concern that PURPA, as implemented, is encouraging the construction of small gas-fired electric generating capacity and is discouraging utilities from constructing additional large powerplants that could produce electricity more cheaply.

I start with the premise that a new, nuclear coal plant, if built and operated efficiently, is the most cost-effective option the Nation has today for meeting our increasing need for electric power.

Our studies show this to be the case.

The legislative history for PURPA suggests that Congress had three goals in mind; encouraging the development of certain types of alternative electric suppliers, as a means of improving the overall efficiency of the electric supply system. Second, providing greater diversity in the Nation's sources of electric power; and third, displacing the use of oil and natural gas in electric generation.

Since PURPA's 1978 enactment, no nuclear or coal-fired electric generating capacity has been ordered, while about 22,000 megawatts of PURPA qualifying facilities have been firmly committed to. Of this total, almost 20,000 megawatts have been gas fired.

As such, I would conclude that PURPA's implementation has been a failure, one which will manifest itself in the late 1980's and early 1990's by higher electric rates for consumers and increased gas consumption for electric power generation. This latter factor will prevent gas from being available for other industrial and residential uses, and will promote increased use of oil, and thus, oil imports.

A contributing factor to this trend is that PURPA creates an artificial and unfair competitive advantage for qualifying facilities over new, nuclear, and coal-fired electric generating capacity. PURPA encourages short-term solutions and discriminates against cost-effective long-term solutions.

Coal and nuclear electric generating capacity is the most capital intensive, has the longest leadtime, but is a long-term cost-effective solution. PURPA qualifying facilities have shorter leadtimes, are not as capital-intensive, but are managed by nonutilities to provide a fast return on investment without regard to our long-term electric power needs.

This discrimination, in combination with ongoing, adversarial relationships that exists between utilities and rate regulators, discourages the development of coal and nuclear power for new electric power supplies. Thus, it is quite likely that the majority of the new electric power supply system will be gas fired, either a combination of PURPA qualifying facilities, or combustion turbines exempt from the Fuel Use Act.

Some recent examples of the continuation of the post-PURPA trend are, as Mr. Miller indicates, Pepco's replacement of a planned coal-fired facility with a combined cycle turbine, firing natural gas; the projected increase of cogeneration in the New England area, from 200 megawatts in 1984, to 2,200 megawatts today.

The third indication is that requests for exemptions from the Fuel Use Act in 1985 and 1986 averaged three times the pre-1985 rate. Since the beginning of 1986, there has been roughly 2,000 megawatts of announced new electric generating capacity; 90 percent of it has been gas fired.

In review of the implementation of PURPA legislation, I would urge that the committee consider procedures and processes that would permit long-term, cost-effective nuclear, and coal-fired facilities to compete on an equal financial basis with other energy sources for new electric generating capacity.

Such action would be consistent with our national energy policy, and would provide the U.S. consumers with the benefits of economical, nuclear and coal-fired electric generating capacity.

This concludes my statement.

[The prepared statement of Mr. Ward follows:]

Testimony by Dennis P. Ward
Before the Committee on Energy and Natural Resources
United States Senate
June 5, 1986

Mr. Chairman, I am Dennis P. Ward, Associate and Head, Environmental Division of Sargent & Lundy. I am appearing before you today representing the Financial Committee of the Atomic Industrial Forum.

As you know, the Atomic Industrial Forum is a trade association with over 500 member organizations. It is dedicated to the peaceful use of nuclear energy for mankind's needs in energy, medicine, food, and industrial development. The member organizations of the AIF include electric utilities, architect-engineers, equipment manufacturers, mining and milling companies, labor unions, laboratories, financial institutions and universities.

First let me thank you for this opportunity to present our views on the implementation of the Public Utility Regulatory Policies Act of 1978.

I start with the premise that a new nuclear or coal plant, if built and operated efficiently, is the most cost-effective option the nation has today for meeting our increasing need for electric energy. Our studies show this to be the case.

The legislative history for PURPA suggests that the Congress had three goals in mind:

- Encouraging the development of certain types of alternative electric power suppliers as a means of improving the overall efficiency of the electric power supply system;
- Providing greater diversity in the nation's sources of electric power; and
- Displacing the use of oil and natural gas in electric generation.

Since PURPA's 1978 enactment, no new nuclear or coal-fired electrical generating capacity has been ordered while about 22,000 MWe of PURPA qualifying facilities have been firmly committed to. Of this total, almost 20,000 MWe have been gas-fired.

As such, I would conclude that PURPA's implementation has been a failure, one that will manifest in the late 1980s/early 1990s by higher electric rates for consumers and increased gas consumption for electric power generation. The latter will prevent gas from being available for other industrial and residential uses and will contribute to increased oil use, thus oil imports.

A contributing factor to this trend is that PURPA creates an artificial and unfair competitive advantage for qualifying facilities over new nuclear and coal-fired electric generating capacity. PURPA encourages short term solutions and discriminates against cost-effective long-term solutions.

-Coal and nuclear electric generating capacity is the most capital intensive, has the longest lead time, and is a long-term cost-effective solution.

-PURPA qualifying facilities have shorter lead times, are not as capital intensive, and are managed by non-utilities to provide a fast return on investment without regard to our long-term electric power needs.

This discrimination, in combination with the ongoing adversarial relationship that exists between utilities and rate regulators, discourages the development of coal and nuclear for new electric power supply.

Thus, it is quite likely that the majority of new electric power supply will be gas-fired, a combination of PURPA QFs and combustion turbines exempted from the Fuel Use Act.

Some recent examples of a continuation of the post-PURPA trend are:

-PEPCO's replacement of a planned coal facility with a combined cycle combustion turbine firing natural gas.

-Projected new QF electrical generation in New England for the 1990s is up from 200 MW in 1984 to 2200 MW today.

-Requests for exemption from the Fuel Use Act in 1985 and 1986 average three times the pre-1985 rate.

Since the beginning of 1986, there has been roughly 2000 MWe of announced new electric supply. Ninety percent of it has been gas-fired.

In the review of the implementation of the PURPA legislation, I would urge that the Committee consider processes that would permit long-term cost-effective nuclear and coal-fired facilities to compete on an equal financial basis with other energy sources for new electric generating capacity. Such action would be consistent with our national energy policy and would provide the U.S. consumers with the benefits of economical nuclear and coal-fired electric generation capacity.

This concludes my statement. I would be pleased to answer your questions.

The **Chairman**. Gentlemen, thank you very much. I appreciate the testimony today and I have just a comment, which is not directed necessarily at any one of the three of you, but at one of the dilemmas we have. I suspect it is a human tendency to pick out the worse case of the opposition and highlight it, and forget either the best case or even an average case.

Cogenerators will look at their best case, look at their opponents worse case; nuclear power will look at the cogenerators' worse case, ignore their best case. I suppose that is a human tendency. It makes it a little more difficult for us to kind of sort out the truth that runs through the statements.

There is also, I noted, Dr. Anderson, and Mr. Miller, in your testimony today something which, again, I suppose is all right, but it makes it a little more difficult; you tend to look at the average performance under PURPA, and say, hey, on the average, this is pretty good.

I guess what we respond to is, where are the aberrations? Where are the instances in which it does not work well? I do not think either of you would contend that in every instance it has worked perfectly. Yet, I read your statement and I get the impression really—do not do anything because there are not any problems. There are some problems.

I do not know that the problems are severe enough for us to deal with, by legislation, but there are some problems.

Yes; I would seek your response, Dr. Anderson.

Dr. **Anderson**. Yes; there certainly are problems. My strong recommendation that PURPA should not be changed is the idea that the problems should not be solved through legislation. The problems require regulatory approval and our recommendations are based on the idea that so many of the problems are utility-specific and cogeneration, or small power production-facility specific. So, even the regulatory problem must be dealt with at the individual State level, many times not even at the FERC level.

So, our recommendation, I would not like for our recommendation to at all be construed as though there are not problems. With any broad piece of Federal legislation, there are going to be implementation problems. What I think we ought to do is look at them as that and not try to correct them at the Federal level.

The **Chairman**. I appreciate that statement. I did not find it anywhere in your prepared material, and I guess that is the reason I made the comment and invited your response.

Gentlemen, thank you very much for your testimony today. I appreciate it.

That concludes our hearing today, and the committee will stand adjourned.

[Whereupon, at 12:55 p.m., the hearing was adjourned.]

APPENDIXES

APPENDIX I

Responses to Additional Committee Questions From Witnesses Appearing June 3, 1986

American Paper Institute, Inc.
260 Madison Avenue, New York, N.Y. 10016/(212) 340-0600
cable address: AMPAPINST New York

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June 30, 1986

The Honorable James A. McClure
United States Senate
Chairman, Committee on Energy
and Natural Resources
Washington, D.C. 20510

Dear Senator McClure:

Enclosed are the responses of the American Paper Institute to follow-up questions from members of the Senate Committee on Energy and Natural Resources regarding implementation of PURPA.

I. Response to Question 1 Regarding PURPA Machines and Qualifying Facility Firing of Oil and Gas:

Fuel efficiency criteria for qualifying facilities should relate to the fuel efficiency of utility generating stations. PURPA machines firing oil or gas are economic in general only when the utility power generation being displaced is fired by oil or gas. In these situations, PURPA machines use less oil or gas than the utility generating units they displace and are more thermally efficient.

Payments to qualifying facilities relate directly to fuel costs of the utility and to the utility's cost of capacity. It is unlikely that PURPA machines receive long term capacity payments unless they have demonstrated the availability of long term oil and gas supplies at competitive costs and displacement of new plant. In the way PURPA was designed and is being implemented, qualifying facilities, including PURPA machines, frequently displace oil and gas fired utility generation. Once the oil and gas use in the utility system disappears due to displacement, avoided costs for new qualifying facilities are no longer based on oil and gas. Therefore, the economic soundness of qualifying facilities using oil and gas is likely to disappear and their development should cease. Critical to this analysis is the reasonable determination of avoided costs by the state utility commissions.

PURPA machine development is economically self-limiting. As long as avoided costs are determined in a reasonable manner and qualifying cogenerators are more thermally efficient than the utility generation they displace, no changes in the rules regarding PURPA machines are needed.

II. Response to Question 2 Regarding Utility Purchase of Capacity When Unneeded:

There is no federal requirement for utilities to buy capacity. PURPA does require utilities to buy power from the qualifying facilities. Whether there is a capacity payment for the power as part of the avoided cost payment is a determination made by the state utility commission. The goal of the state utility commission is to assure the ratepayers an adequate continuing supply of power at the lowest reasonable cost. The state commission determines whether energy and capacity payments are appropriate based on information supplied by the utility, commission staff, and others participating in hearings. In almost all situations, there are energy costs to be avoided. In some situations, commissions determine there are no new facilities to be avoided in the planning horizon -- often a twenty year time period. Most state commissions do not give capacity credits in these circumstances; some do, however, knowing that the qualifying facilities will be on line beyond the planning horizon and hoping to secure less expensive capacity against the day when it is needed. It is appropriate that these determinations are made at the state level as opposed to the federal level.

III. Response to Question 3 Regarding Full Avoided Cost:

FERC appropriately determined that full avoided cost would maximize development of qualifying facilities, meeting the objectives of PURPA for greater energy efficiency, increased reliability of the nation's electric grid, greater use of renewable fuels, and reduced dependence on imported oil. If less than full avoided cost is offered for qualifying facility power, less power will be made available. If less qualifying facility power is made available, the utility must supply more power. The ratepayer will be required to pay at least the utility's avoided cost and potentially more, due to utility cost overruns, for the utility power. This is not consistent with the goal of supplying adequate power at the least cost to the ratepayer.

Practically, many contracts for qualifying facility power are made at less than full avoided cost because they contain other benefits to the qualifying facility. Also, many state commissions determine avoided costs based on information supplied by utilities whose cost estimates and forecasts are below actual costs that could be avoided. Utilities do not have the best record of forecasting the cost of new plant and equipment. Cost overruns and plant cancellations reflect this fact. Ratepayers would be endangered economically if rates paid to qualifying facilities were set below 100% of avoided cost since utilities' costs would increase in the future for expensive operations and plants, which should have been displaced by qualifying facilities.

Further, as is discussed in response to your first question, in "those areas where there has been extensive development of qualifying facilities," the utilities' avoided costs have *fallen* (*e.g.*, Idaho, Maine, California) by more than the drop in fuel prices due to displacement of the most expensive utility generation, while at the same time many of the most likely sites for qualifying facility development have been utilized. It is particularly important that full avoided costs be maintained as the standard in these circumstances, so that new beneficial and cost-effective qualifying facilities can be developed.

The pulp and paper industry appreciates the opportunity to share this additional information for the record. Should your committee seek further information, do not hesitate to contact the American Paper Institute at (212) 340-0667.

In addition, we would like to take advantage of your kind offer to allow us to supplement the record with the attached statement in which we respond to some of the utility testimony on PURPA rules and clear up areas of possible confusion.

Sincerely,

William J. Nicholson

William J. Nicholson
Chairman
Electricity Committee

WJN:cd

Cogeneration Coalition Of America, Inc.
2 Lafayette Centre
1133 21st Street, N.W.
Suite 500
Washington, D.C. 20036
Phone (202) 887-5200

June 30, 1986

The Honorable James A. McClure,
Chairman
Senate Committee on Energy
and Natural Resources
Room 358
Senate Dirksen Office Building
Washington, D.C. 20510

Dear Chairman McClure:

On behalf of the Cogeneration Coalition of America, Inc. (Coalition), I wish to express appreciation for the opportunity to participate in the discussions and recent hearings regarding the implementation of the Public Utility Regulatory Policies Act of 1978.

Set forth below are the Coalition's written responses to questions submitted from Senator J. Bennett Johnston for the PURPA oversight hearings record:

(1) The Coalition believes that fuel choice and "PURPA machine" issues are being effectively handled in the marketplace through the laws of supply, demand and price. This keeps the federal government out of energy decisionmaking regarding fuel selection and is consistent with the current National Energy Policy Plan V. Neither PURPA nor its implementing rules and regulations should be transformed into a program to favor one fuel over another, while electric utilities enjoy unbridled access to all fuel sources under recent amendments to the Powerplant and Industrial Fuel Use Act and pending legislation to repeal that Act. Furthermore, consistent with this policy, the Coalition recommends that all current limitations on fossil fuel use for small power production facilities be suspended for at least the next five years.

Furthermore, from an energy planning perspective, it should be recognized that short-term use of efficient gas-fired cogeneration technologies is an important bridge to the development of other cogeneration technologies, including fuel cells and those which use coal in various combustion, gasification, and liquefaction systems -- technologies which could help the nation prepare for any new natural gas shortages.

(2) Consumers benefit significantly from cogeneration because the technology offers three major advantages over conventional methods of energy production: increased fuel efficiency, lower capital investment costs, and greater flexibility in responding to fluctuations in demand. However, if consumers are actually to receive the maximum net benefit, cogenerators and all other participants in the electric industry must have greater access to transmission service.

Greater wheeling authorities could be devised through the FERC to provide a balancing of benefits and protection to ratepayers and individual customers while not compromising utility planning and transmission system reliability. These objectives could be sustained through consideration of the following types of requirements:

a) While basic statutory authority exists as a matter of federal law, state commissions should be provided with discretion to adopt procedures and ancillary policies which balance fairly the interests of all customers served by the electric utility.

b) While voluntary wheeling should be further encouraged for QFs, provision should be made as a matter of regulation to under certain circumstances order wheeling which would focus on whether the affected utilities in fact have, or can reasonably be expected to add, the transmission capacity necessary to provide wheeling services.

c) While wheeling arrangements could be made by either the host electric utility or the purchasing electric utility, the qualifying facility should have the choice of which electric utility makes the wheeling arrangements.

d) The FERC should provide further support for the rights of an individual state commission to require wheeling of self-generated power to satellite plants of an end user as a matter of state policy.

e) The electric utility should bear the burden of proving lack of capacity, degradation of reliability, or other factors related to the inability to provide requested wheeling services. The FERC should establish a rebuttable presumption that the capability to wheel exists.

f) At least two types of wheeling service should be provided on a firm and as available basis. The threshold for an inability to provide wheeling service should be minimal in the case of firm wheeling requests.

g) Wheeling rates should be developed on a cost of service basis. Due consideration should be provided for factors such as firmness, reliability, and time and use considerations as well as other relevant factors.

h) Upon request of the qualifying facility, any electric utility should be required to establish non-discriminatory wheeling tariffs. Wheeling orders, tariffs and arrangements should be public information and be available in a readily retrievable format to ensure maintenance of non-discriminatory terms and conditions.

i) Except in unusual circumstances, decisions on a wheeling application should be rendered on a fixed time schedule basis. The relevant Commission should have the responsibility to resolve disputes expeditiously and the authority to order interim wheeling subject to refund obligations. This is a critical requirement since generally wheeling cases, unlike rate cases, are rarely settled before the FERC.

j) Industrial or commercial users who cease firm purchases, undertake wheeling and then desire to reestablish firm purchases and service should be viewed as new customers by the electric utility unless other arrangements, such as standby rates, or contracts have been negotiated by the parties.

k) The relevant Commission should have the authority to order appropriate modifications to the transmission system to facilitate wheeling if a net cost attributable to a wheeling application are borne by that applicant, and the electric utility is unable to demonstrate significant adverse impact on the system.

(3) The full avoided cost standard is necessary to encourage the maximum development of cogeneration and small power production at a rate which is not detrimental to utility ratepayers and, in most instances, will inure to the direct benefit of utility ratepayers. The rationale underlying this proposition has been succinctly summarized previously by the

American Paper Institute, Inc. in a discussion of the economic efficiency of full avoided cost rates, as opposed to either a "percentage of avoided cost" or "split-the-savings" approach. This rationale is as follows (footnotes are excluded):

> FERC has properly exercised its discretion only if the rate adopted is both just and reasonable to electric consumers and carries out PURPA's mandate of encouraging cogeneration. During the course of its lengthy rulemaking proceedings, FERC came to the conclusion that granting a full avoided cost rate was the only way it could reasonably meet both prongs of this test.
>
> One of the most important obstacles to cost-effective cogeneration has been the reluctance of utilities to pay adequate rates for power purchased from cogenerators. Thus, even where utilities were willing to purchase power, investors in cogeneration could not rely on sufficient income to meet their costs, much less to justify the risk and major capital expense of investment. The result, as might be expected, has been that a vast untapped resource has lain dormant. The paper industry, for example, is currently operating at about one-third of its potential cogeneration capacity.
>
> There is, of course, no magic number at which cogeneration becomes economic for all potential cogenerators or even for cogenerators within a single industry. Local energy costs, plant design and process steam requirements are but a few of the many variables which make the cogeneration investment decision sui generis for each QF. If some QF's can operate economically at 3 cents/kWh, others may not be practical at less than 8 cents/kWh. Yet, as discussed earlier, if the cogenerator can produce electricity at a cost to the utility no greater than it would otherwise incur in producing or purchasing that electricity, the public, and the utility, will benefit. To extract every possible kilowatt of cost-effective cogeneration, it is necessary to set rates at the highest level which does not entail added costs to the utility's other customers.
>
> The full avoided cost rate -- the cost to the utility of generating or purchasing an equivalent increment of power -- attains that

optimum level. Thus, the utility incurs no added expense by meeting its requirements with cogenerated power instead of utility-generated power. If rates are set any higher than full avoided cost, an additional burden is placed on the utility (and its customers) because, by definition, cheaper power is available elsewhere. If rates are set any lower than full avoided cost, however, valuable potential cogeneration capacity will be lost at the margin. Either result would be arbitrary and capricious in light of PURPA's express directives, and would therefore constitute an unjustifiable exercise of FERC's rulemaking power.

"Split-the-savings" and "percentage of avoided cost" rates, which petitioners propose as alternatives to full avoided cost rates, offer unsatisfactory solutions to the pricing problem. Either of these pricing schemes will result in a rate which is lower than full avoided cost and either will inevitably induce less investment in cogeneration. Moreover, to the extent these alternatives would allow consumers to escape paying their full share of the utilities' avoided cost of power, they would result in a subsidy of consumers by QF's. This result is as clearly inconsistent with PURPA's goals and policies as would be the subsidy of QF's by consumers.

But "split-the-savings" and "percentage of avoided cost" rates suffer from other, equally critical, infirmities. The "split-the-savings" approach necessarily entails a detailed inquiry by regulatory authorities into each QF's power production costs. This kind of inquiry is inconsistent with the spirit of § 210(e) of PURPA, which is intended to exempt QF's from the regulatory burdens common to utility ratemaking proceedings. More importantly, it is simply unacceptable to private industry.

The pulp and paper industry is a highly competitive one in which many companies operate on a small margin of profitability. Because cogeneration is a process which is highly integrated with the manufacturing process itself, power production costs to some extent reflect production costs as a whole, and are consequently of competitive interest. Few if any companies in the industry will publicize

> such sensitive information. As noted earlier, power production is at best a sideline in the pulp and paper industry. The paper companies cannot afford to jeopardize their principal business concern, viz. paper product sales, for what will always be a small source of additional revenue to the industry.
>
> In addition to the fact of disclosure, utility-type rate-making regulation would require an unjustifiable commitment of time and management resources to the regulatory process, with top management subject to examination at public hearings on matters of business policy. This kind of regulatory imposition is anathema to the pulp and paper industry and will not, as a rule, be borne simply to obtain the potential economic return from power production.
>
> The bottom line is clear. Undue regulatory burden and public disclosure of costs entailed in the "split-the-savings" approach, will cause many paper companies to abandon otherwise cost-effective cogeneration investment.
>
> Finally, both the "split-the-savings" and "percentage of avoided cost" approaches are misconceived because they allocate part of the financial benefits of cogeneration to the utilities even though those utilities bear little or none of the risk of investment. It is axiomatic in business that benefits should accrue to the person or entity taking the risks. In the instant case, QF owners put up all the money and reorder manufacturing processes and capital investment decisions to bring cogeneration on line. To the extent possible, consistent with the rights of utility consumers, QF's must be the ones to reap the financial rewards of these risks. Full avoided cost rates are the appropriate vehicle for this risk-benefit allocation.

Regarding the growth of cogeneration and small power production, while projected data indicate that independent power production has more than doubled since the enactment of PURPA, these projections are based on purchase power contracts with qualifying facilities rather than the actual construction of such facilities. On a contract basis, these estimates range to levels of approximately 20,000 megawatts by the end of 1985. The level of actual QF penetration is currently under study by the Federal Energy Regulatory Commission under contract with

Hagler, Bailly and Company. This study should verify that the success factor for QF development will be substantially lower than purchase power contracts. This study should be completed by December, 1986, and will provide for the first time greater detailed information regarding QF penetration since the enactment of PURPA, as well as a review of the various reasons why individual QF projects did not reach final completion. In our experience, the predominant reasons for failure to complete projects range from environmental and siting reasons, uneconomical QF purchase power contracts, an inability to finance projects, shifting federal tax policies, and constantly revised state regulatory policies.

While critics argue that this increase in QF power has been at the expense of higher rates to utility customers and decreased system reliability, there is no substantial evidence offered to support this position. The Department of Energy has concluded that in the long term, contracts for QF power have not had adverse rate implications for electric utility ratepayers. In some instances, it can be specifically validated that such contracts have provided desirable benefits to ratepayers. Houston Lighting and Power has recently indicated that its firm capacity cogeneration contracts have saved ratepayers approximately $150 million. Based upon Southern California capacity projections, the presence of QF power during 1984 provided a critical margin of protection for system reliability in light of rapidly escalating demands for electricity in this service area.

The DOE study also indicates that there are only three electric utilities which purchase more than three percent (3%) of their total electricity from cogenerators and small power producers nationwide. Based upon this data which is representative and derived from the broader national experience, current purchases of QF power to date have not had any adverse affects on utility customer rates and system reliability. In the long term, the presence of QF power based upon full avoided costs can provide stability and reliability to long-range electric utility planning.

Alternatively, if a standard other than full avoided cost were developed, the most equitable approach would be based upon value pricing with increased transmission access. All new sources of electricity should receive the same purchase power rates whether they are built by electric utilities or third parties. Utilities should receive QF rates for their own new projects as well as paying QF rates to third parties who bring in new projects. In this fashion, the utilities will have a strong incentive to see that QF rates are set correctly, and that they are properly adjusted to keep up with changing conditions. Placing the electric utility in this position will essentially guarantee that their estimates of QF prices will be as sensitive, realistic and accurate a reflection of market realities as possible. Value pricing, in conjunction with better QF access to the transmission system, could facilitate maximum economic efficiency, and maximize consumer benefits.

The avoided cost standard and related issues are discussed in greater detail in the enclosed article from the June 12, 1986 issue of the Public Utilities Fortnightly, which we hereby submit for the written record to further respond on the points discussed herein.

Thank you for the opportunity to respond.

Sincerely yours,

Michael J. Zimmer
President

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Cogeneration: Boon or Bane To Consumers?

By MICHAEL J. ZIMMER and BEVERLY E. JONES

This article is a broad review of issues associated with the development of cogeneration as an electricity source that has followed enactment of certain provisions of federal law in the 1970s, with special attention to the interface between cogeneration projects and regulated electric utilities. The interests of the two industries have sometimes appeared divergent, and the contribution of these authors is a reasoned attempt to demonstrate that a flourishing cogeneration industry is not a threat to utilities and their friendly coexistence will serve the public interest.

Recently we visited a paper mill, located in a northern industrial area with a troubled economy, to look at its new gas cogeneration system. A paper company executive told us that a few years ago management had faced the fact that the company had to either significantly reduce its energy expenses in order to bring down its product costs, or close the mill and give notice to more than 250 employees. The company chose to install the cogeneration facility, which now is producing the steam used in processing its specialty paper products and also is generating most of the mill's electricity.

Today, the mill is still in business, the local electric utility continues to provide a portion of the facility's electricity needs at a higher, special rate, and the local gas company is selling an additional gas load. Both utilities have kept residential customers who may have been forced to move after losing jobs at the mill, as well as their business customers within the supporting commercial infrastructure.

Both gas and electric ratepayers are benefiting because the utilities can spread fixed costs over a somewhat broader base than would have been possible without the mill on-line. Also, since less fuel is consumed to do the same amount of useful work as was performed with conventional technology, the nation is conserving energy. Moreover, such benefits are made possible through the use of domestic energy resources, predominantly American technology, and equipment manufactured in large part in the U. S., rather than from abroad.

Cogeneration is not always the answer to industry's energy problems, but where thermal and electricity needs are appropriately balanced, everyone involved can come out ahead. Thus, it is not surprising that during the seven years since enactment of the Public Utility Regulatory Policies Act,[1] tremendous growth has occurred in the development and use of cogeneration.[2] Whether measured by the increase in total dollar amounts expended on cogeneration equipment and related systems, by the number of applications for qualifying facility status filed with the Federal Energy Regulatory Commission, or by the increase in the nation's electrical capacity contributed by cogeneration systems, it is clear that cogeneration is contributing significantly to America's energy supply and has become an important factor in planning for the nation's energy needs to the year 2000.

This growth in cogeneration has not been achieved without some struggle. Unfortunately, that struggle often has involved a portion of the energy industry which could stand to gain the most from a cooperative partnership with the budding cogeneration industry — the electric utilities.

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[1] Pub. L. No. 95-617, 92 Stat. 3144 (1978). PURPA is one of five major federal statutes enacted in 1978, collectively known as the National Energy Act. Aimed at alleviating the national energy crisis, PURPA was designed to encourage conservation and efficiency in energy use, to regulate wheeling of bulk power, and to provide incentives for industrial cogenerators and small power producers.

[2] Cogeneration is the sequential production of both electrical (or mechanical) energy and thermal energy from the same primary energy source. According to a recent edition of *Cogeneration Report*, filings by cogenerators at the Federal Energy Regulatory Commission have grown so explosively that the FERC is planning a tracking survey of cogeneration and other qualifying facilities. "FERC Wants to Track 'Mind Boggling' Cogeneration Boom Through a Survey," *Cogeneration Report*, March 15, 1985, at 1. A separate inventory of all installed cogeneration facilities nationwide is under consideration by the American Gas Association under contract with GKCO, Inc.

Of course, a number of electric utilities have enthusiastically welcomed the opportunities offered by cogeneration. Many of their recent annual reports indicate that electric utility after utility has come to recognize the flexibility and efficiency which cogeneration development can provide. A recent brochure, entitled "Cogeneration," published by CSW Energy, Inc., a subsidiary of Central and South West Corporation, makes the electric utility case for cogeneration in this way:

> The future belongs to the efficient, which means there may be a cogeneration facility in your company's future.
>
> Cogeneration is, among other things, an energy bargain — the simultaneous production of two useful forms of energy, normally steam and electricity, from single fuel source. . . .
>
> Today, cogeneration is staging a comeback for several reasons. Higher energy costs, stricter environmental regulations, and federal incentives have boosted cogeneration. But the primary selling point is its inherent efficiency. At a time when business is aggressively seeking ways to operate and manufacture their products more efficiently, cogeneration is becoming increasingly attractive.

Our discussion, however, will respond to the recurring criticisms of cogeneration raised by some electric utilities during debate before state utility commissions, the media, consumers, and legislatures. A careful evaluation of these allegations suggests that their motivation often is not, as claimed, the prevention of harm to the electric grid, to consumers, and to other energy sectors, but, rather, the preservation of the current structure of the electric utility industry.

Before addressing the various allegations, we will briefly review some of the benefits which cogeneration offers — benefits which are acknowledged even by cogeneration opponents, and which have been predominantly unchallenged since 1978.

Cogeneration Offers a Range of Benefits

Cogeneration provides three major advantages over conventional methods of energy production: increased fuel efficiency, lower capital investment costs, and greater flexibility in responding to fluctuations in demand.

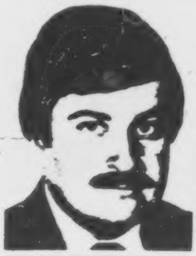
As CSW said, the primary benefit which cogeneration offers is overall *improved efficiency of fuel use.* The amount of fuel needed to produce both electric and thermal energy from a cogeneration system is less than the total fuel needed to produce the same output of electrical and thermal power separately, using conventional technologies. For example, ten barrels of oil fueling a cogeneration system will produce the same amount of electricity and thermal energy which conventional systems require about 12 barrels of oil to produce.[3] Because of this efficiency, cogeneration systems lower the net cost of electrical and thermal energy by 15 to 20 per cent. For many energy-intensive industries and commercial users, cogeneration can mean the difference between a profitable or a losing operation.

Another significant advantage of cogeneration relates to the financing of new generating capacity, a major aspect of utility economics. Relative to conventional power plants, cogeneration facilities generally are smaller in scale and require a lower capital investment. The facilities' smaller size makes it possible to avoid many of the site-location and attendant environmental problems faced by electric utilities in building major capital additions. Shorter construction lead times also contribute to cost savings by reducing interest charges.[4]

A typical cogeneration facility today costs $800 to $1,300 per kilowatt of electric capacity, less than half the cost per kilowatt of new conventional coal or nuclear capacity. Moreover, with private development and financing of cogeneration facilities, the ratepayer is not exposed to the risks of escalating financing costs, construction delays, completion risks, and cost overruns. With cogeneration, he only pays for the power he gets — no more, no less.

A related benefit of cogeneration is greater flexibility in servicing demand. Not only is cogeneration capacity less expensive than many conventional options, but it can be brought on-line more quickly, as short-term demand escalates. Cogeneration technology provides a means to add small increments of electric capacity to the nation's electricity supply, reducing required lead times and the chances of overbuilding. This will assume growing importance as capacity shortfalls appear by the early 1990s.

In addition to offering these acknowledged benefits,



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[3] "Industrial and Commercial Cogeneration," Office of Technology Assessment, U. S. Congress, OTA E-192, February, 1983, at 7.

[4] Unfortunately, some major electric utilities rather than work effectively and in good faith with cogeneration and small power producers have favored reliance on increased dependency on foreign electricity imports from Canada, and new capacity additions through combined-cycle plant additions.

cogeneration technology is attractive because it is well proven and commercially available — boilers, steam and gas turbines, reciprocating engines, generators, and waste heat recovery equipment have all been available for decades, and are subject to continuing research and development efforts towards improvement.

Generally discounting these broad benefits, critics of cogeneration development have presented an array of arguments which can be roughly divided into two categories: (1) alleged negative impacts of the technology itself and (2) unfairness to particular groups claimed to result from the current legislative and regulatory treatment of cogeneration. We now will address these two sets of arguments, beginning with claimed negative impacts.

Net Environmental Effects Are Positive

A few opponents of cogeneration have argued that both oil- and gas-fired cogeneration threaten the environment, particularly air quality. They maintain that cogeneration growth will increase the levels of nitrogen oxides and particulate emissions, primarily in urban areas where cogeneration facilities would for the most part be powered by internal combustion engines. For example, a Consolidated Edison Company of New York, Inc., spokesman recently testified before the Senate that operation of diesel cogeneration facilities in urban areas would result in "diesel exhaust, discharged from rooftop chimneys in close proximity to the [cogeneration] facility's own fresh air intakes and those of its neighbors."[5] This position is still maintained by Consolidated Edison today.

Contrary to these assertions, no reliable evidence suggests that cogeneration will lead to a decline in air quality or any other aspect of the environment. In fact, depending on the type of cogeneration system installed and the fuel used, the fuel efficiency of cogeneration leads directly to a net decrease in total emissions associated with the production of thermal and electrical energy.

A recent Environmental Protection Agency analysis[6] also confirms this fact. Among the EPA's findings was that generally total emissions declined where cogeneration was added to a utility system. The EPA concluded further that, under all possible regulatory scenarios, the emissions from cogeneration are favorable relative to current utility and industrial emissions.[7] Comparable analytical efforts undertaken earlier last year by the California Energy Commission confirm EPA's results.

Even with respect to urban areas, where the potential danger to air quality is greatest, allegations regarding environmental impacts of cogeneration have been overstated and are without substantiation. The Office of Technology Assessment's 1983 national study[8] concluded that any problems caused by urban density, and the small-scale cogeneration systems which would be used in such areas, can be avoided if facilities are "designed and sited carefully, including choosing an engine model with low emissions, applying existing technological emission controls, and ensuring that the exhaust stacks are taller than surrounding buildings."[9] Further, cogeneration facilities, like other industrial or commercial facilities, continue to be subject to air pollution control regulations, which the OTA study recommended be suspended only on a case-by-case basis, dependent upon a demonstration of positive net impact on air quality. California has led the way in such regulation in 1985, and other states may follow suit later this decade.

Cogeneration Does Not Produce Safety Problems

Some electric utilities have argued that cogeneration can have a dangerous impact on the safety and integrity of the nation's electric grid system. They maintain that the automatic interconnection of cogeneration facilities (operated by "nonutility specialists") and highly technical electrical grid systems present an increased likelihood of system failure and danger to electric utility workers and others. Large numbers of grid-connected cogenerators, they further argue, could overload utility system dispatch capabilities.

Although safety concerns are legitimate, they are exaggerated, particularly under existing regulatory safeguards. FERC rules authorize state regulatory authorities to establish safety and reliability standards for interconnected operations.[10] Existing requirements ad-

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[5] Statement of Bertram Schwartz on behalf of Consolidated Edison Company to the Subcommittee on Energy Regulation of the Committee on Energy and Natural Resources, United States Senate, May 24, 1982, at 19.

[6] "Net Emissions Impact of Cogeneration, Four Case Studies," U. S. Environmental Protection Agency, April 28, 1981. The utility systems included in the study are Commonwealth Edison Company, Gulf States Utilities Company, New York State Electric and Gas Corporation, and Pacific Gas and Electric Company.

[7] See *Id.* at 1, 3-4.

[8] See Footnote 3.

[9] See *Id.* at 17.

[10] 18 C.F.R. § 292.308 (1984).

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dress such critical interconnection issues as specifications of interconnection equipment, the point of interconnections, voltage at interconnection points, safety and protection equipment, procedures required of both the cogeneration facility and the electric utility facility, and supervisory responsibilities. Our experience has indicated that interconnection rules promulgated by state public service commissions are working, and that compliance is achieved readily through direct negotiations with electric utilities.

Placing safety concerns in the proper perspective, the 1983 OTA study found the widely varying costs of interconnection charged by electric utilities to be a more critical issue than the safety aspect itself. "Most of the technical aspects of interconnection are relatively well understood and can be priced out realistically . . . [W]hile proper interconnection must be ensured in order to protect utility workers' safety, none of the necessary precautions is difficult to implement."[11]

Also enhancing the safety and technical aspects of cogeneration interconnection are the maturity of the relevant technologies and the experience of major industry participants. Oil- and gas-fired cogeneration technologies have been used throughout the United States and Europe since the 1880s. Developers and builders of cogeneration systems today include some of the most sophisticated corporations in the electric generation and technology industries — companies like Thermo Electron Corporation, General Electric Company, Babcock and Wilcox Company, and Combustion Engineering, Inc. Many of these same companies were selected by electric utilities in the 1970s to design, build, operate, and maintain large power plants for their own systems.

Over the last two years, about one-half of the Fortune 500 companies have entered the cogeneration industry,[12] generating power either for their own operations or for a third party. The expertise of these participants, combined with state and federal regulatory oversight of interconnection, contributes to the industry's continuing positive safety record.

Moreover, the development of cogeneration actually reduces the risks of systemwide electricity failure. By dispersing electric utilities' sources of supply, cogeneration lessens the likelihood of a systemwide failure caused by the failure of a single, major electricity generating source. Possible system overload also can be avoided.

To date, there has been no reported accident or systemwide failure of an electric grid as a result of a cogeneration interconnection. For the future, the likelihood of systemwide failures or accidents can be reduced only if the electric utility industry decentralizes its sources of supply through the help of cogeneration and other alternative energy production methods.

Cogeneration Will Not Result in Energy Market Imbalances

Other arguments which have been made by cogeneration opponents are that increased cogeneration development will drastically impact either electricity rates or oil and gas prices. Some have projected a "death spiral" scenario, whereby a shift towards cogeneration, spurred by the economic incentives of PURPA, will produce a shortfall in kilowatt-hour sales to key electric utility customers. Fixed costs per kilowatt-hour will rise as sales fall and utility capacity is idled. Higher fixed costs will reduce revenues below the "fair rate of return" and force rates upward, which, in turn, will set the spiral off again.

These rather hysterical arguments assume unrealistically high estimates of future electrical capacity displacement. They ignore the significant fact that the economic feasibility of cogeneration depends upon the existence of uses for the waste energy. Cogeneration potential has definite constraints because there are a limited number of industrial and commercial opportunities where the balance between electricity usage and thermal or mechanical energy usage will support the economies dictated by capital and fuel costs.

A recent study of cogeneration potential prepared for the Department of Energy[13] demonstrates that cogeneration will always represent a relatively small proportion of the nation's electric capacity. The accompanying table compares DOE's estimates of industrial cogeneration potential for the 15-year period beginning in 1983 to the total actual operating capacity of all reporting utilities in 1983. Even if the entire 15-year potential cogeneration capacity had been placed in service in 1983 alone, cogeneration would have comprised only 6 per cent of total U. S. generating capacity.

This potential cogeneration capacity can be absorbed, when it does actually come on-line over the next fifteen years, without creating economic dislocations to the electric utilities. What may be even more significant, however, is that the evolutionary incremental shift towards cogeneration could cause less displacement in the electric utility industry than the likely alternative — the shutting down of existing industrial plants.

Notwithstanding the inherent market limitations on cogeneration growth, critics also have argued that cogeneration development could lead to significantly increased demand for oil and gas, forcing prices upward and heightening U. S. reliance on foreign oil supplies. Gas price increases would be particularly steep for "high priority" gas users, it is argued. Interruptible electric generation loads have traditionally been effective load balancing mechanisms for natural gas distributors, mak-

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[11] See Footnote 3, at 36.

[12] "Analysts Told to Expect More Small Units, Industry Shakeout, Utility Challenges," *Cogeneration Report*, March 15, 1985, at 8.

[13] "Industrial Cogeneration Potential (1980-2000) for the Application of Four Commercially Available Prime Movers at the Plant Site," Dun and Bradstreet Technical Economic Services and TRW Energy Development Group, prepared for DOE, August, 1984.

[redacted]

Summary of Cogeneration Potential Compared to Current Capacity of Operating Power Plants as of 1983 (Megawatts)

STATE	POTENTIAL INSTALLED COGEN. CAPACITY (1)	TOTAL CURRENT INSTALLED ELEC. CAPACITY (2)	COGEN. AS A PERCENT OF TOTAL ELEC. CAPACITY
ALABAMA	1,017	19,199	5.30
ALASKA	185	1,444	12.81
ARIZONA	145	11,015	1.32
ARKANSAS	353	8,796	4.01
CALIFORNIA	3,944	39,821	9.90
COLORADO	135	6,501	2.08
CONNECTICUT	258	6,107	4.23
DELAWARE	188	2,053	9.16
DIST OF COLUMBIA	1	868	0.12
FLORIDA	1,016	31,893	3.19
GEORGIA	920	17,562	5.24
HAWAII	147	1,482	9.92
IDAHO	21	2,020	1.04
ILLINOIS	1,408	29,710	4.74
INDIANA	502	18,700	2.68
IOWA	482	8,815	5.47
KANSAS	583	9,488	6.14
KENTUCKY	534	15,965	3.34
LOUISIANA	3,298	15,695	21.01
MAINE	529	2,396	22.08
MARYLAND	410	9,816	4.18
MASSACHUSETTS	533	9,910	5.38
MICHIGAN	631	22,058	2.86
MINNESOTA	370	8,610	4.30
MISSISSIPPI	385	5,825	6.61
MISSOURI	271	15,720	1.72
MONTANA	0	3,219	0
NEBRASKA	217	5,895	3.68
NEVADA	5	4,564	0.11
NEW HAMPSHIRE	250	1,536	16.28
NEW JERSEY	1,418	13,785	10.29
NEW MEXICO	206	5,393	3.82
NEW YORK	2,126	32,040	6.64
NORTH CAROLINA	882	18,419	4.79
NORTH DAKOTA	221	3,828	5.77
OHIO	2,103	27,467	7.66
OKLAHOMA	475	12,560	3.78
OREGON	454	10,576	4.29
PENNSYLVANIA	2,512	34,826	7.21
RHODE ISLAND	82	270	30.35
SOUTH CAROLINA	960	12,316	7.79
SOUTH DAKOTA	0	2,432	0
TENNESSEE	654	18,188	3.60
TEXAS	5,110	57,615	8.87
UTAH	72	3,032	2.38
VERMONT	38	949	4.00
VIRGINIA	704	11,513	6.11
WASHINGTON	700	21,808	3.21
WEST VIRGINIA	260	15,156	1.72
WISCONSIN	1,241	10,721	11.58
WYOMING	308	5,920	5.20
TOTALS	38,344 MW	555,455 MW	6.90

SOURCES: (1) Dun & Bradstreet Technical Economic Services and The Energy Development Group, Prepared for U.S. Dept. of Energy. Industrial Cogeneration Potential (1980–2000) for Application of Four Commercially Available Prime Movers at the Plant Site (August 1984).

(2) As reported by all utilities to Department of Energy.

ing it possible for "high priority" natural gas consumers to enjoy uninterruptible gas service at lower rates. Gas-fired cogeneration systems arguably could not provide this load balancing service, since small cogenerators are less capable of handling supply interruptions and load shifts. Therefore, it has been argued that a substantial loss of electric generation loads would boost gas rates to high-priority users, as gas distributors were forced to take on greater gas supply commitments in order to guarantee noninterruptible supply.

Acceptance of this argument leads to the incongruous policy of encouraging natural gas use by electric utility generators at a 33 per cent efficiency rate, while denying gas use to cogeneration systems capable of operating at 80 per cent efficiency. Further, the hypothesized increase in gas prices, even for high-priority users, is unlikely to occur for several reasons.

First, in many areas of the country, any new gas loads from cogeneration would serve only to partially offset the decline in existing or expected gas industry sales to other consumers. For example, in the Ohio valley, an area with high potential for cogeneration development, industrial and residential gas use have fallen by 35 per cent and 20 per cent, respectively, over the past decade. Even if the majority of that region's cogeneration potential were realized, only about one-tenth of the decline in gas sales would be effectively recovered.

Moreover, although the impact of cogeneration development on gas prices is likely to be small, it probably will be positive. An average 30 per cent of the delivered price of gas is essentially a fixed cost. Increases in gas loads brought about by cogeneration systems operate to mitigate these fixed-cost charges to existing gas consumers by spreading the recovery of these dollars over greater sales volumes. This impact is particularly important to existing gas consumers because of the more general decline in gas sales experienced over the past decade.

Even where cogeneration growth does produce a net increase in gas sales, the replacement gas actually might be less expensive than some current components of gas supply. A portion of the nation's current gas supply is from historic "high cost" gas contracts, whereas newly contracted gas now costs approximately one-third less at the wellhead. Also, additional supplies from Canada are becoming available for the long term and are priced at levels competitive with domestic gas and alternative fuels.

Finally, from an energy planning perspective, it should be recognized that short-term use of efficient gas-fired cogeneration technologies is an important bridge to the development of other cogeneration technologies, including fuel cells and those which use coal in various combustion, gasification, and liquefaction systems — technologies which could help the nation prepare for any new natural gas shortages. By 1990, the most attractive cogeneration investments will be fueled by solids, rather than by oil or gas, with growing market acceptance of atmospheric fluidized bed combustion technologies.

With regard to the oil market, it has been argued occasionally that advancement of oil-fired cogeneration technologies will lead to increased oil consumption, contrary to the basic goal of PURPA and other cogeneration legislation of the 1970s. Again, this argument ignores a key point: Cogeneration uses energy more efficiently than competing technologies, so it will *always* produce more energy per unit of any type of fuel — coal, gas, and nontraditional feedstocks, as well as oil. Moreover, OTA concluded that oil-fueled cogeneration would not represent a major share of cogeneration growth because of price and supply uncertainties, coupled with current commercial and regulatory disincentives to the use of oil.[14] Also, of course, there are no signs of an imminent natural gas shortage which could cause a shift to oil-fired systems, and knowledgeable forecasters are continuing to project natural gas prices to track with oil prices.

Unpersuaded by evidence of the oil-conservation potential of cogeneration, some critics continue to press for adoption of fuel-use tests, under which a cogeneration system would be required to prove net oil savings over the facility's useful life. Some states have recently expressed growing interest in such limitations. In evaluating the effectiveness of a fuel-use test which would be applied before qualifying status and tax benefits could be bestowed upon a cogeneration facility, the 1983 OTA study estimated the total potential oil savings to be as low as 60,000 to 90,000 barrels per day in 1990, and perhaps less because such an expensive and time consuming requirement would discourage the development of even cogeneration systems that could save oil.[15]

In examining the impacts upon the energy market, the basic fact to keep in mind is that cogeneration, powered by any fuel, is more efficient[16] than conventional technologies for the separate production of thermal and electrical energy. Cogeneration represents an effort by the industrial and commercial sectors to curtail their energy-related costs, and thereby sends market and price signals to all energy producers, including oil and gas producers. Efficiency and accurate price signals remain, in the long run, key factors in achieving a more stable and secure energy future, and cogeneration already has assumed a major role in providing these important national benefits.

The Net Tax Revenue Effect of Cogeneration Is Positive

A few cogeneration critics have argued that the industry's development could undercut the tax base. Because cogenerators pay no state or local taxes on the power they produce, public treasuries suffer a loss when taxable electric utility sales are displaced, according to these arguments.

Estimation of the net tax effect of cogeneration, however, does not end with a calculation of the direct tax loss. While state and local tax revenues may decline due to a reduction in utility-supplied sales of electricity, among the offsetting factors to take into account are contributions made by the increase in business, income, sales, service, and other taxes paid by the rapidly growing cogeneration industry. A recent study by Frost and Sullivan estimated that the cogeneration equipment industry would generate $5 billion in sales by the end of 1984. From a longer-term perspective, the entire cogeneration industry, including installation, sales, and maintenance, was forecast to gross over $60 billion by the year 2000.[17]

In addition to boosting sales and other excise tax receipts, indirect tax benefits of cogeneration development accrue with the upward re-assessment of property values to reflect the increased value of sites on which cogeneration systems are located. Such property tax increases alone are likely to offset any direct loss in city tax revenue owing to a decline in utility-supplied power sales.

Finally, and perhaps most significantly, an evaluation of the tax impact of cogeneration must reflect the direct tax loss to many localities which would occur without cogeneration. As was the case with the paper mill, cogeneration can play a critical role for an individual community, by assisting established industrial facilities to stay in business. Moreover, on a national scale, cogeneration offers the chance to decrease energy costs, leading to a better business climate, which in the long run will bring more stable tax and revenue growth for all jurisdictions.

Statutory Cogeneration Incentives Are Justified and Necessary

The arguments which we have addressed so far are built around alleged disadvantages of cogeneration. A second set of arguments is voiced more loudly and frequently and centers on federal policies to encourage cogeneration development. The current legislative scheme, incorporated in PURPA and other bills passed in the late 1970s and early 1980s,[18] essentially provides six types of incentives for cogeneration use:

- Exemptions from certain federal and state statutes and regulations;
- Clarification of the tax status of cogeneration projects for depreciation purposes;
- Energy tax credits;
- Interconnection with utility facilities and the right

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[14] See Footnote 3, at 182.

[15] See *Id.* at 269.

[16] We recognize, however, the development propensities of a few large national project developers to propose cogeneration projects of marginal efficiencies in order to maximize the electric production cycle. The activities of these developers have led to a constrained regulatory environment leading to moratoria in three states — i.e., California, Idaho, and Montana — and severely restrictive development policies in two others; i.e., New York and Texas.

[17] "The Cogeneration Equipment and Services Market in the U. S.," Frost and Sullivan, Inc., May, 1983, at 170-172. This forecast was adjusted downward by the publisher in 1985 in response to several factors, while packaged cogeneration systems were broken out for separate study.

[18] In addition to PURPA, the other sources of these incentives are: Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3351 (1978); Energy Tax Act of 1978, Pub. L. No. 95-618, 92 Stat. 3174 (1978); Powerplant and Industrial Fuel Use Act of 1978, Pub. L. No. 95-620, 92 Stat. 3289 (1978); Crude Oil Windfall Project Tax Act of 1980, Pub. L. No. 96-223, 94 Stat. 229 (1980).

to backup or supplemental power available from utilities;

- Flexibility in using natural gas as a fuel; and
- Rights for cogenerators to sell electricity to electric utilities at the utilities' "full avoided cost," and to purchase electric power from the utilities at "nondiscriminatory rates."

Of these incentives, the right to sell cogenerated electricity at a utility's "full avoided cost"[19] has provided the greatest impetus for cogeneration development since 1978, and, as such, is the provision most vehemently criticized by some utilities, users, and state regulatory commissions.

Full avoided cost represents the expense an electric utility would have incurred to itself produce electricity, had it not "avoided" that production by the purchase of electricity from a cogenerator. Opposition to the avoided cost formula focuses both on the specific issue of fairness to the electric utility ratepayer and on the more general question of whether the formula is one aspect of an unfair or unnecessary subsidization of the cogeneration industry.

Before looking at the impact on utility ratepayers of full avoided cost payments, we would again reiterate that — nationwide and in any single region — cogenerated electricity will always represent a fairly small portion of an electric utility's total available capacity, as defined in the accompanying table. Today, cogeneration and other small generating technologies provide about 7 per cent of total electrical power produced in this country. Of this fraction, a significant portion of cogenerated power is used internally and therefore is not subject to avoided cost purchases. Because full avoided cost payments apply to such a small percentage of generated power, it is difficult to empirically identify any impact at all which such payments have on utility customers.

The structure of avoided cost payments itself demonstrates that the operation on utility ratepayers should be no worse than neutral. Avoided cost payments are based upon a *utility's own estimates of its own costs.* The payments consist of two elements, both of which a utility would have incurred had it generated that quantity of power itself: (1) the energy cost and (2) the capacity cost.

When there is a need on the part of the utility for the extra capacity provided by the cogeneration facility, avoided cost payments are based on both these costs. In such a case, a utility, and ultimately its customers, are paying no more for the added capacity than they would have paid had the utility been forced to install the new capacity itself, rather than relying on the cogenerator.

The ratepayer is not forced to pay a greater amount for cogenerated electricity than he would have paid for electricity generated from other sources of incremental capacity, and in most instances he will pay less. Furthermore, the payments cover only electricity which is actually delivered. During the development phase, the ratepayer bears none of the risk that cogeneration capacity will be constructed and successfully placed online. Once the facility is operational, the ratepayer pays for cogeneration capacity only when the facility actually is operating and not during scheduled or unscheduled outages.

Where a utility is required to purchase power from a cogenerator but has no immediate need for excess capacity, the avoided cost payment is based *only* on the energy cost avoided by the utility. The ratepayer is not made to pay for unneeded capacity. Some states have provided for capacity payments in such instances to spur cogeneration development, particularly for the early years of a project. However, over the full contract life, adjustments can be devised to ensure that ratepayers are protected and allowed to pay no more than full avoided costs over the total term of the agreement.

Very few sales of cogenerated electricity actually are made at full avoided cost. Recent national experience consistently confirms our own empirical evidence that rates for the purchase of cogenerated electricity generally average from 90 to 92 per cent of full avoided costs as concessions for other nonprice considerations. Some electric utilities in the Northeast have consistently reported purchase power rates as low as 85 per cent of full avoided costs. Data trends also indicate that since 1984 more cogeneration projects are being sized to track with thermal and electrical demands of the facility for on-site use, with no sales of power back to the grid. To lower the avoided cost obligation mandated by PURPA and implemented by the states would in reality draw the avoided cost purchases down to levels of, perhaps, 75 to 80 per cent of the full avoided cost, discouraging development of many cogeneration projects, and removing the risk premiums necessary to secure project financing.

The state of California's own case study of cogeneration systems confirmed that "a utility-offered price equal to the utility avoided cost is a major, if not critical, factor in the decision of most entities to undertake a cogeneration project."[20] Practical involvement in utility negotiations verifies that the full avoided cost standard is critical to create a better balance in purchase power negotiations between the developer and the utility. This initial balance creates a more conducive environment leading to successful completion of contract negotiations on both price and nonprice terms. Even with this balancing effect, recent experience has yielded mixed results, as subtle forms of delay, obfuscation, and confusion have been injected into many negotiations.

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[19] The FERC defines "avoided costs" as the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source. 18 C.F.R. § 292.101(b)(6).

[20] "Case Study Analysis of Fourteen Cogeneration and Small Power Production Systems," California Public Utilities Commission, 1982, at p. 6-2.

The effectiveness of the avoided cost formula in stimulating cogeneration growth has spurred claims that it results in unfair subsidization of the cogeneration industry. Other federal provisions, which confer financial and other operating advahtages on cogenerators, have drawn similar attacks. Electric utilities, their customers, and taxpayers, it is claimed, are bearing the financial burden of the nationwide electric utility system which make it possible for cogenerators to benefit from sales of power to electric utilities. Implicit is the argument that the cost savings which cogeneration makes possible should be shared more directly with current ratepayers.

An accurate historical perspective of the electric utility industry is one key factor in evaluating and responding to the argument that the cogeneration industry is being subsidized and that the subsidization is unfair. Regulated and protected for years, established electric utilities already enjoy a wide range of tax incentives, subsidies, and benefits. Under the current Internal Revenue Code, the electric utility industry has been one of the most subsidized and protected of American industries, according to congressional sources.

The practice of normalization accounting, for example, permitted under the current provisions of the code, allowed the 150 largest electric utilities in the United States to bill ratepayers in 1982 for $7.1 billion to cover taxes of which only $2 billion was actually paid.

Given its tradition of federally mandated assistance, the electric utility industry is in no position to base its opposition to cogeneration on the economic advantages conferred by federal legislation, such as PURPA, which attempted to levelize the imbalance which evolved in the course of history since the 1960s on such issues as purchase power obligations, interconnection, and standby service rates. Furthermore, even with PURPA, substantial imbalances exist among the states with respect to their full implementation of these requirements.

Another consideration is that the subsidization argument does not take into account the serious problems which led to the passage of PURPA and related legislation or the benefits that cogeneration can offer ratepayers, electric utilities, U. S. industry, and the general economy. Understanding that increased use of cogeneration and small power production facilities would reduce the demand for traditional fossil fuels, Congress carefully designed PURPA to achieve definite goals, including the removal of the institutional and operational barriers to development of cogeneration facilities.[21] The fact is that PURPA is today working precisely as intended.

Although there are distinct limits to the role which cogeneration can play, wherever it is economically and technically feasible it leads to greater energy efficiency and, in the long term, reduced demands for fossil fuels. All Americans also benefit from more efficient use of depletable natural resources, reduced environmental pollution, diminished reliance on foreign sources of energy, and increased reliability of electric service from small-scale dispersed power generators. Finally, cogeneration is truly an American enterprise. It uses largely American technical know-how and equipment, and this strong domestic base cannot be ignored, particularly in the face of the nation's continuing substantial dependence on imported fuel and power alternatives.

Not only do Americans, generally, benefit from cogeneration, but the advantages provided to the electric utility industry, and its ratepayers, constitute an independent justification for current cogeneration incentives. For example, accelerated cogeneration development can improve the financial health and ratings of electric utilities through reduced capital requirements. Debt and equity issuances at either high interest rates or prices below book value can be postponed, with positive benefits to electric utilities and their customers. On this basis, several of the more entrepreneurial electric utilities today are encouraging the development of cogeneration in their own regions to boost revenues and attract investors through unregulated subsidiaries.

In those cases where an electric utility faces an immediate demand for increased capacity, the short construction schedules and low capital costs of cogeneration facilities ensure that capacity can be provided as quickly and cost effectively as possible, which is a critical advantage under the financial and regulatory constraints currently faced by utilities. The cogeneration option is necessary and is a more attractive American option than increased power exports from Canada.

The availability of cogeneration facilities permits utilities to make optimal economic decisions regarding the expansion of generating capacity and replacement of oil- and gas-fueled power plants. Over time, cogeneration can lower the incremental cost of generating electricity, since cogeneration facilities tend to supplant the most expensive contributions to a utility's generation mix. As this incremental "avoided cost" declines, the purchase price for cogenerated power is reduced, as is the overall cost of power to the electric utility ratepayers. Because of their smaller size, reduced construction time, and higher operating efficiencies, cogeneration facilities offer electric utilities a better opportunity to match demand with supply and thereby to lower their reserve margins. This cuts costs for the utility, and in turn reduces the rates for its customers on a strategic basis.

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[21] *See Federal Energy Regulatory Commission v. Mississippi*, 456 U.S. 742, 47 PUR4th 1, 72 L.Ed.2d 532, 102 S.Ct. 2126 (1982), reh den. 458 U.S. 1131, 73 L Ed.2d 1401, 103 S. Ct. 15 (1982).

In return for these benefits, public policy confers the most direct cost savings upon the cogenerators, who assume all of the financial risks of providing cleaner, more efficient use of energy for the future, in the manner contemplated under PURPA and implemented under the protections of state public service commissions.

Conclusion

In reviewing the most common arguments against development of cogeneration, it becomes clear that the critics may be resisting the evolution of the electric industry from one which operates in relatively insulated marketplaces into a more competitive industry confronting lower prices and dependable service. The Federal Energy Regulatory Commission has moved the gas industry in this direction this year, and we believe it could promote comparable structural revisions to the electric industry by 1987.

The benefits of cogeneration to society and to industrial and commercial energy users have been demonstrated. Electric capacity has value to the utility industry now, including power provided by cogeneration. Capacity is required as borne out by the electric utility industry's own long-term forecasts, the combined-cycle development plans of at least a dozen utilities, and the vigorous exploration of Canadian exports by utilities in the Northeast and Midwest.

Now is the time for the electric utilities to accept the new electricity marketplace and to work with cogenerators to achieve a system by which, together, the two industries may satisfy their mutual objectives through the next century.

Natural Gas Prices Decline with Oil as Demand Increase Seen

U. S. natural gas prices are tracking the decline of world oil prices and will result in an ultimate increase in gas demand, according to the American Gas Association. "In general," AGA President George H. Lawrence reports, "declining crude oil prices are accelerating the decline of natural gas prices. This in turn will lead to increased competitiveness of natural gas prices relative to coal and electricity and increased gas sales in certain markets. On the downside of the oil price drop, it will result in reduced natural gas drilling activity, gas reserve additions, and deliverability."

An AGA study, "Implications of Falling Crude Oil Prices for the U. S. Natural Gas Industry: 1986 Update," finds that if the refiner acquisition price of crude oil remains at $15 per barrel, retail natural gas prices would decline 14 to 17 per cent.

There is the prospect of substantial load growth for natural gas due to lower oil prices. According to the AGA analysis, at $15 per barrel for crude oil, additional gas load per year by 1988, exclusive of losses to oil, would total between 870 and 1,090 billion cubic feet (Bcf) (210 to 430 Bcf from coal, electricity, and less conservation; 660 Bcf from greater economic activity). Overall, *net* gains in gas sales averaging 130 to 150 Bcf per year are projected for the 1987 through 1990 period, inclusive. "We have the gas supply to meet that additional load," Lawrence said, "despite a likely fall in gas drilling activity if oil prices stay low. Gas producers will respond to gas demand."

For the rest of 1986, however, with $15 per barrel for oil, the gas industry could experience a *net* load loss of 40 Bcf to 330 Bcf. (U. S. natural gas consumption by end users totaled 17.3 trillion cubic feet in 1985.) The potential load loss is estimated at 480 Bcf because of switching to residual oil by electric utilities and heavy industry. That total loss, however, would be partially offset by a gain from other sources of between 150 and 440 Bcf this year.

If crude oil prices were to remain in the $15 per barrel range for an extended period of time, gas drilling activity would fall almost 20 per cent. Yearly additions to natural gas reserves could end up about 35 per cent below current levels, according to the study. "Natural gas exploration and production activity is declining as a result of falling gas prices and lack of demand," Lawrence said. "However, increased gas sales resulting from repeal of the Fuel Use Act and incremental pricing provisions of the 1978 Natural Gas Policy Act would increase gas demand and thereby increase producer revenue, resulting in a revitalization in natural gas exploration activity."

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July 18, 1986

The Honorable James A. McClure
Chairman, Committee on Natural
  Resources
United States Senate
Washington, DC 20510

Dear Senator McClure:

Thank you for the opportunity to testify before your Committee and to respond to the follow-up questions from Committee Members. The hearing record may be closed before you receive our response, but we trust our replies will aid you and the other Members of the Committee in understanding how electric consumers have been affected by PURPA and the manner in which it has been implemented.

We strongly urge you and your Committee to take action to insure that the original intent of PURPA is achieved in a fair and equitable manner for all those effected without returning to an over dependence on the scarce resources, oil and natural gas.

Sincerely,

Calvin J. Hebert

Calvin J. Hebert
Senior Vice President-Operations

CJH/DEH/dc

Attachment

cc Senator J. Bennett Johnston

PURPA OVERSIGHT HEARING QUESTIONS SUBMITTED FOR THE RECORD FROM SENATOR J. BENNETT JOHNSTON

(1) The Committee heard significant testimony concerning so-called "PURPA machines" -- oil or natural gas-fired cogeneration facilities that satisfy FERC's efficiency standards but that produce more electricity and burn more fuel with less efficiency than would be the case if the facilities were sized to meet their thermal needs. Given the fact that oil and natural gas are ultimately scarce resources, wouldn't national energy policy be better served by requiring the electrical capacity of an oil or gas-fired qualifying cogeneration facility to be a function of the thermal need to be served?

Some cogeneration facilities use a portion of their steam for feedwater heating or use a condenser to increase their electrical output. The incremental heat rate or efficiency of the electrical energy produced is probably not as good as utility central stations due to the size and higher pressure designs of utility plants. Also, cogeneration decisions that achieve electric to thermal ratios that meet or exceed the needs of most industrial processes are based on either natural gas or oil fired equipment. The cost of similar coal fueled facilities are normally too high to justify their installation considering the current relative cost of fuels. The end result is that most cogeneration, and the bulk of the potential projects, utilize our ultimately scarce resources, oil and natural gas.

So called, PURPA machines depend upon capacity payments based on the avoided cost of coal or nuclear utility units to be economically viable if they are sized to sell power to the utility. Basically, gas fueled PURPA machines can be built for about 500$/KW, coal central stations for 1200$/KW and nuclear for 3000$/KW. In fact, capacity payments to a natural gas dependent cogenerator based on avoided coal or nuclear cost is a direct subsidy by the utility ratepayer to private power producers with the end result that the ratepayer has a greater dependence on ultimately scarce resources. The mechanism almost guarantees a repeat of the natural gas and electric power shortages experienced along the Gulf Coast during the late 70's and early 80's. Increased consumer costs will accompany these shortages just as it did in the past. The consumer's exposure to increased costs associated with capacity payments could be reduced by requiring the cogenerator to demonstrate the capability of utilizing the same fuel used to determine the capacity payment he receives. Existing thermal energy utilization standards would be appropriate for facilities with solid fuel capability.

The present efficiency standard as applied to natural gas and oil is either 42.5% or 45%, with a concomitant thermal energy requirement of 15% or 5%, respectively. A new efficiency standard should be applied to facilities that are capable of using only natural gas or oil. A properly designed standard would optimize the use of these scarce resources and effectively cause most designers to size their projects around their thermal energy needs in the most fuel efficient manner. Efficiencies of 70-95% are achievable with normal system components depending on the amount of thermal energy recovered (based on published manufacturers performance data) with the proposed efficiency calculation below. An efficiency standard that would almost certainly produce the desired result without discriminating against commercially-available equipment is 65% with a slight change in the calculation methodology. No minimum thermal energy usage would be required.

The current approach in PURPA regulations of ignoring 50% of the thermal energy recovered for determining efficiency of energy utilization does not encourage efficient thermal use. The proposed method of calculating the PURPA efficiency would differ from the existing methodology as shown below:

EXISTING

$$\text{efficiency} = \frac{\text{Power} + (1/2)(\text{Useful Thermal Energy})}{\text{Fuel*}}$$

PROPOSED

$$\text{efficiency} = \frac{\text{Power} + \text{Useful Thermal Energy}}{\text{Fuel*}}$$

* The lower heating value (LHV) of the fuel is used in this calculation. This methodology has some hidden implications, i.e., (1) fuel is purchased based on higher heating value (HHV) and use of the LHV understates consumption by about 10% for natural gas, (2) use of the LHV of the fuel causes efficiencies to be higher than generally accepted practice, (3) the HHV has been the standard used for decades by industry. However, it will be retained to minimize the changes in the formula above and to facilitate comparison between the increased energy savings of the proposed methodology and the current methodology.

(2) Is there any justification for requiring utilities to buy capacity from qualifying facilities that the utilities do not need within their existing planning horizons? Doesn't this represent a net cost to consumers?

Requiring utilities to purchase unneeded capacity does indeed increase cost to the consumer and there is no justification for doing so. GSU has recently completed construction of a nuclear unit and has ample capacity for the next decade. GSU is regulated by both the Louisiana PSC and Texas PUC. Neither has required capacity payments and it would be a misapplication of PURPA to do so.

Consumers, however, are still going to see a net increase in cost because large industrial customers are installing their own generation to supply their internal electric and steam requirements. The standby and power purchase provisions of PURPA and the manner in which they are being implemented by FERC and state regulators encourages industrial customers to generate their own power. The net effect is to spread the utility's fixed cost over a smaller base with increased per kwh cost to the remaining consumers. Currently, displacement projects totaling about 790 MW are being built in GSU's service area representing 15% of the 1985 peak of 5139 MW. The ratepayer and/or the utility's investors will absorb the increased cost. GSU is proposing a rate discount for industrial customers as long as they do not utilize the potential they presently have to install their own generation. Eighteen industrial customers will qualify for the proposed discount rate with loads totaling about 430 MW, an additional 8% of peak. The total impact of self generation and rate discounts could amount to about 19% of GSU's operating income. Ultimately, consumers will make up this loss either directly through increased utility rates or indirectly through increased borrowing costs.

The key to self generation is the provision in PURPA requiring the utility to standby at non-discriminatory rates. Most regulators interpret this provision to mean at actual cost of providing standby service. The remaining electric consumers would be protected if PURPA were revised to say "standby service would be provided at non-discriminatory rates when utilities have reserves of less than 25% and at a compensatory rate otherwise." Once a qualified facility contracts for a non-discriminatory standby rate, the facility would qualify for a non-discriminatory rate for its remaining life.

Some utilities do have a need for additional capacity. These utilities should be allowed to use a bidding procedure with capacity payments limited by the utility's avoided capacity cost. The proposed repeal of the Fuel Use Act should be completed; and, if practical, a utility allowed to use the cost of natural gas fueled facilities as their avoided cost in determining the capacity payments.

(3) What justification is there for retaining a 100 percent full avoided cost standard? If there was, for example, an 80 percent avoided cost standard, electric consumers would directly receive the savings, namely, the 20 percent difference between the utility's avoided cost and what it would be required to pay a qualifying facility. Originally, FERC considered a less-than-full avoided cost standard but rejected it because little development of qualifying facilities was expected, and encouragement of a diversified power supply was thought to be more important. However, the growth of cogeneration and small power production has exceeded original expectations. In those areas where there has been extensive development of qualifying facilities, couldn't there be a provision for the payment of less-than-full avoided cost rates without discouraging further development?

Utilities should be allowed to bid or otherwise negotiate with cogenerators to allow the best possible deal for the electric consumer. Competitive pricing of energy purchased from cogenerators will help to insure the optimum use of both capital and fuel resources. Preference should be given to cogenerators using solid fuel instead of natural gas or oil. Utilities could have an 80 percent avoided cost standard that would be applied to a limited quantity of cogenerated energy. The minimum quantity would prevent cogenerators from backing out base load designed coal or nuclear utility units and protect the electric consumer from the capital cost involved in changing the utility's mix of base and swing capacity. As currently implemented, PURPA is not protecting the consumer from these additional capital cost.

A declining avoided cost scale based on overall efficiency would be an ideal way of giving preference to cogenerators using solid fuel. The price paid to generators for power produced from natural gas or oil could be multiplied by the overall efficiency of the cogenerator. This pricing scheme would provide an incentive for the cogenerator to optimize his overall thermal use of these scarce resources. For example, a gas turbine with an unfired heat recovery steam generator can expect to achieve overall efficiencies of 65-75%. With supplemental firing, similar equipment achieves between 90-95% efficiency, a far better utilization of scarce resources. These levels of efficiency are calculated by taking credit for all the thermal energy and using the lower heating value of fuel.

HOUSTON LIGHTING & POWER COMPANY
P. O. BOX 1700
HOUSTON, TEXAS 77001

D. E. SIMMONS
GROUP VICE PRESIDENT

June 27, 1986

The Honorable James A. McClure, Chairman
United States Senate
Committee on Energy and Natural Resources
Washington, DC 20510

Dear Senator McClure:

Thank you for allowing Houston Lighting & Power Company the opportunity to testify before your committee at the recent hearing on the implementation of the Public Utility Regulatory Policies Act of 1978.

HL&P supports the efforts of this committee in developing policy recommendations that are in the national interest. Thus, we are pleased to respond to Senator Johnston's follow-up questions.

Enclosed you will find our written responses to the questions, as well as supplemental testimony that I request to be made part of the official record.

Please call on Houston Lighting & Power Company to provide any assistance possible and to participate fully in the activities of this committee.

Sincerely,

HOUSTON LIGHTING & POWER COMPANY

D E Simmons

D. E. Simmons
Group Vice President
of Power Operations

DES/ba

Enclosures

HOUSTON LIGHTING & POWER COMPANY'S WRITTEN RESPONSES TO QUESTIONS SUBMITTED FOR THE RECORD BY SENATOR J. BENNETT JOHNSTON AS A FOLLOW-UP TO PURPA OVERSIGHT HEARINGS

1. Q: The Committee heard significant testimony concerning so-called "PURPA machines" -- oil or natural gas-fired cogeneration facilities that satisfy FERC's efficiency standards but that produce more electricity and burn more fuel with less efficiency than would be the case if the facilities were sized to meet their thermal needs. Given the fact that oil and natural gas are ultimately scarce resources, wouldn't natural energy policy be better served by requiring the electrical capacity of an oil or gas-fired qualifying cogeneration facility to be a function of the thermal need to be served?

A: Yes, for the following reasons:

a. Cogenerators often make the claim that cogeneration is twice as efficient in terms of extracting useful energy as is utility power production, but rarely is it explained that "twice as efficient" is approaching a maximum efficiency, and achieving this level of efficiency is entirely dependent on the design of the project. We recently reviewed the typical energy efficiencies for topping cycle qualifying facilities and central station power plants in HL&P's service area to determine whether cogeneration facilities built in our area were really that efficient. We found that although the technology exists to achieve overall energy use efficiency levels in the 70-80% range, seldom did we find one of that efficiency in our area. We did find that the overall energy use efficiencies for some of the projects in our area is only marginally higher than that of a new combined cycle plant that a utility would build. An example of such a facility is a 445 MW cogeneration facility that is being built in our service area that will use seven times as much fuel for power generation as it would to solely produce process steam and electricity as a "by product." Typically, a 37-MW gas turbine with a supplementary fired heat recovery boiler could provide the process steam needs of the facility.

Such a distortion of PURPA's intent is possible because the FERC rule defining the efficiency standard for topping cycle facilities permits cogenerators to produce twice as much electricity as thermal energy. A more appropriate approach could be devised by simply redefining the FERC efficiency standard so that it weights electrical output and thermal output equally.

Those projects with high overall energy use efficiency are those which match electrical output to thermal output as closely as possible. Therefore, projects which burn more fuel than is necessary to meet the thermal output requirements so that they can generate excess amounts of electricity are not maximizing fuel efficiency. The current standard is:

FERC Efficiency Standard = Electrical Output - one-half the thermal output divided by the total energy input.

The suggested approach of having these facilities closely match electrical production to the thermal requirement would support national energy policy's fuel diversification objectives. This approach can be implemented by changing the FERC certification requirements for oil or natural gas-fired topping cycle cogeneration facilities applying for Qualifying Facility status so that the cogenerator is required to demonstrate that the electrical capacity of his proposed facility is limited to that which corresponds to the maximum production of useful thermal energy.

b. As a matter of national energy policy, HL&P believes very strongly that fuel diversification is a priority objective that should not be abandoned just because the temporary instability in the oil and natural gas markets has led to falling prices. Federal policymakers must balance the long-term objectives of stability in fuel supply availability and price against the short-term opportunities to lower fuel costs. Given the need to pursue these objectives, we would recommend that oil and gas-fired cogeneration be treated differently from solid fuel based cogeneration for avoided cost calculation and payment. This will be discussed below in our response to the third question.

2. Q: Is there any justification for requiring utilities to buy capacity from qualifying facilities that the utilities do not need within their existing planning horizons? Doesn't this represent a net cost to consumers?

A: HL&P does not believe that there is any justification for utilities to purchase capacity from cogenerators if they do not need it, because such payments above full avoided cost represent subsidies from electricity consumers to cogenerators.

Payments for capacity which is not needed by the utility is contrary to PURPA's concept of ratepayer indifference. The concept of avoided cost is predicated on the assumption that the utility avoids either capacity or energy.

In effect, if a utility purchases capacity from a cogenerator when it is not needed, the ratepayers are paying twice for the same power. Assuming the utility has adequate capacity to meet its reserve requirements, the rates consumers are currently paying are compensating the utility for its prior investment in facilities through depreciation and return on invested capital. If at the same time, the ratepayers are paying for capacity purchases from cogenerators, then they are paying twice. Only if the utility is able to avoid building or purchasing capacity do the ratepayers benefit from purchases of capacity from qualifying facilities.

3. Q: What justification is there for retaining a 100 percent full avoided cost standard? If there was, for example, an 80 percent avoided cost standard, electric consumers would directly receive the savings, namely, the 20 percent difference between the utility's avoided cost and what it would be required to pay a qualifying facility. Originally, FERC considered a less-than-full avoided cost standard but rejected it because little development of qualifying facilities was expected, and encouragement of a diversified power supply was thought to be more important. However, the growth of cogeneration and small power production has exceeded original expectations. In those areas where there has been extensive development of qualifying facilities, couldn't there be a provision for the payment of less-than-full avoided cost rates without discouraging further development?

A: HL&P does not believe there is any justification for retaining the 100% avoided cost standard. Under the "full avoided cost" standard, utility ratepayers are denied an opportunity to benefit from cogeneration purchases. By definition, if a utility pays a cogenerator the "full avoided cost" for the power, the ratepayer is charged exactly as much as he would have been had the utility generated the power.

FERC should evaluate whether avoided cost has been properly defined. There are occasions when the cogenerator's cost of production should be considered in defining avoided cost, to prevent such a situation as exists in Texas whereby our ratepayers are paying for capacity from cogenerators at the expensive cost per kilowatt to build a lignite plant, even though the natural gas-fired cogenerator's cost of producing that power is much less.

It is our Company's position that given the significant profit-making potential cogeneration offers, and given the rapid pace of cogeneration development that has occurred to date, it is highly unlikely that the full avoided cost standard is required as an means of encouraging cogeneration development.

It is now time for federal policy to force cogeneration to compete on the basis of market economics with other electricity supply options so that our ratepayers will be allowed to benefit directly from cogeneration. Implementation of this policy can take one of several forms: relying on a competitive bidding process among cogenerators for establishing buyback rates; mandating discounts off avoided costs, such as those suggested in the question; or redefining the avoided cost formulas and specifying that payments above avoided cost are not allowed. To the extent that avoided cost is used as a basis for payment, oil and gas-fired cogenerators should be paid based on avoided capacity costs of oil/gas-fired combined cycle power generation (with capacity payments made only if capacity is needed and if this would be a prudent addition to the purchasing utility's generation mix) with energy costs based on the utility's actual avoided energy costs over the life of the project. Solid fuel-fired cogeneration should be compensated based on avoided coal-fired capacity and coal-based energy costs.

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LOGAN E. LANHAM
Senior Vice President - Public Affairs

June 30, 1986

The Honorable James A. McClure
The United States Senate
368 Senate Dirksen Office Building
Washington, DC 20510

Dear Senator McClure:

Pursuant to your letter of June 13, 1986 requesting follow-up questions requested by Senator J. Bennett Johnston, we are pleased to submit the following answers:

(1) The Committee heard significant testimony concerning so-called "PURPA machines" -- oil or natural gas-fired cogeneration facilities that satisfy FERC's efficiency standards but that produce more electricity and burn more fuel with less efficiency than would be the case if the facilities were sized to meet their thermal needs. Given the fact that oil and natural gas are ultimately scarce resources, wouldn't national energy policy be better served by requiring the electrical capacity of an oil or gas-fired qualifying cogeneration facility to be a function of the thermal need to be served?

(1) The Senator is in fact correct that oil and natural gas ultimately are scarce resources--in fact, they are finite resources. It appears that it would be in the national interest for the National Energy Policy to prohibit qualifying utilities from utilizing natural gas to fire cogeneration facilities. As Mr. Calvin H. Hebert, Gulf States Utilities Company, testified before the Senate Energy and Natural Resources Committee, the Fuel Use Act dictated the elimination of the use of natural gas as fuel on existing power plant boilers after 1989 and prohibited the construction of new gas-fired generation units. While the requirement to eliminate gas as a fuel in existing plants has been repealed, the second prohibition remains in effect, but only for electric public utilities. It appears to me our nation cannot justify allowing cogenerators to burn oil and natural gas to generate electricity and to force utilities to buy this energy while at the same time prohibiting utilities from building their own plants utilizing the same fuel. It appears that continuing this policy can do nothing less than force utilities to purchase cogenerated electricity produced by burning trillions of cubic feet of natural gas to generate electrical energy while at the same time forcing utilities to convert their present gas-fired generation to other fuels such as nuclear or coal. The only results can be unnecessary increases in consumer energy costs.

(2) Is there any justification for requiring utilities to buy capacity from qualifying facilities that the utilities do not need within their existing planning horizons? Doesn't this represent a net cost to consumers?

(2) There is no justification at all for requiring utilities to buy capacity or energy from qualifying facilities when the utilities are (1) in surplus and (2) surplus within the region. Such a policy has a number of contradictions. As an example, under PURPA, a utility is forced to buy energy from qualifying facilities even when the utility has a surplus. Normally, whenever a utility is in surplus, it cuts back or reduces production of its highest cost energy first and then the next highest cost, and so on until its energy requirements are balanced. On page four of my testimony presented before the United States Senate Committee on Energy and Natural Resources on June 3, 1986, I used the example of Idaho Power of being forced to purchase energy at the same time it was spilling energy over the spillway at its dams. At the time we were paying an exorbitant price for this energy, more than seven cents per kilowatt hour--and selling it at a price ranging from ten to thirty mills a kilowatt hour.

Another example was on page five of my testimony which states:

> "During the period April 1 through May 20, 1986, Idaho Power received approximately 59,400 MWHrs of energy from QFs and paid nearly $3 million for that energy, an average of approximately 50 mills/kWHr. During the same period, Idaho Power made surplus sales in the amount of approximately 840,000 MWHrs at an average price of 9.9 mills/kWHr. The surplus sales were made primarily from excess hydro generation (water was spilled past the majority of our hydro projects during this entire period), thermal displacement that we received from Bonneville Power Administration and QF's energy. Since the purchase price of the QF's energy was considerably higher than the price we received for surplus sales, the QF's transactions resulted in a $2.4 million monetary loss to the Company's customers."

(3) What justification is there for retaining a 100 percent full avoided cost standard? If there was, for example, an 80 percent avoided cost standard, electric consumers would directly receive the savings, namely, the 20 percent difference between the utility's avoided cost and what it would be required to pay a qualifying facility. Originally, FERC considered a less-than-full avoided cost standard but rejected it because little development of qualifying facilities was expected, and encouragement of a diversified power supply was thought to be more important. However, the growth of cogeneration and small power production has exceeded original expectations. In those areas where there has been extensive development of qualifying facilities, couldn't

there be a provision for the payment of less-than-full avoided cost rates without discouraging further development?

(3) The question points out the confusion as to the proper interpretation of the term "avoided cost". The avoided costs of a utility are based upon estimates of what will occur in the future, i.e. what are the additional resource needs of a utility and what will be the cost of acquiring those resources. In short, what costs the utility can "avoid" if it purchases cogeneration. If either the cost estimate and/or the forecast of need is wrong, the "avoided costs" of the utility will be wrong. When rates paid for cogeneration are based on 100 percent full avoided costs, there is an assumption avoided costs can be mathematically determined with precision. This is obviously not the case. No one can predict the future resource needs of utilities with mathematical certainty, as recent history has so dramatically demonstrated.

When the above is coupled with the fact that CSPP developers are permitted to participate in the proceedings to determine a utility's avoided costs, it becomes apparent that CSPP developers will seek to have the utility's CSPP avoided cost rates set at the highest level possible. As a result, the probability is that in today's energy markets, the rates a utility must pay cogenerators will exceed 100 percent of its true avoided cost. That's what Idaho Power has experienced. Most certainly, a payment of "less-than-full avoided cost rates" could be implemented. Avoided costs after all are only broad estimates based upon assumptions that will most certainly change.

Thanks again for allowing us to participate in the PURPA Oversight Hearing. Should additional information be requested, do not hesitate to call me at (208) 383-2266.

Sincerely,

Logan Lanham
Senior Vice President -
Public Affairs

LEL:km

C: Senator J. Bennett Johnston

RESPONSES TO QUESTIONS BY SENATOR JOHNSON
BY JAN HAMRIN, PH.D. ON BEHALF OF THE
INDEPENDENT ENERGY PRODUCERS ASSOCIATION ET. AL.

7/11/86

1. Why should gas cogeneration projects be allowed to proceed given that gas is a scarce resource?

Gas cogeneration is a more efficient use of gas than the separate production of electricity and steam using gas. In many parts of the country, most notably California, New England, the mid Atlantic states, and Texas, gas or oil is the marginal fuel for generation in large numbers of hours of the year. If gas can beat the efficiency of the existing system, it should not be discouraged. If it cannot, it will not be economic to build and operate.

In areas where gas is not the incremental fuel for large numbers of hours, coal is generally the incremental fuel and the pricing structure will tend to be unfavorable to the financing of gas cogenerators. To the extent that capacity is not needed, the prices will be low. (See response to next question) To the extent that baseload (e.g., coal) capacity would be added, the price structure of that capacity would be based on high fixed costs and low variable costs. Since cogeneration has high and fluctuating variable costs, it would be very difficult to finance under that price structure. The market therefore makes it difficult to build gas cogeneration where gas is not the incremental fuel.

Moreover, utilities are increasing their dependence on gas and oil despite the fuel use act. We have identified at least three new major combined cycle projects which are now under advanced planning or construction: the repowering of the Midland plant of Consumers Power Company in Michigan; the Ocean State Power project in Rhode Island (selling power to a number of members of the New England Power Pool) and a plant in advanced planning by Potomac Electric Power Company. In addition, other utilities are now considering such construction. In its most recent avoided cost filing to the Connecticut Department of Public Utility Control, Northeast Utilities stated that its next avoided plant would be a combined cycle in 1997, not a baseload plant. Under such conditions, when utilities are planning oil/gas generation, gas cogeneration should not be discouraged.

Finally we note that even in areas currently served by coal-fired generators, diversifying the resource mix with gas cogeneration could be valuable. In particular, it would reduce the potential for future acid rain or costly retrofits and plant modifications to prevent it. A study by the Carolina Power and Light Company--a utility with about 5200 MW of coal generation at 19 units--indicated that acid rain reduction at its own coal units would cost $2.4 billion in 1983 dollars with an operating cost of $260 million per year. Gas-fired cogeneration would not have this level of environmental effects and pollution control costs.

In sum, if state regulatory commissions are thoughtful and creative, they can design a QF program which incorporates gas cogeneration into that state's resource mix consistent with the other resources and needs of that state.

2. Why should utilities be required to buy power at all under circumstances when they do not "need" the power?

If a utility does not need power, the price for that power should be relatively low while it is not needed. It would reflect a very low price for capacity in the near term (although perhaps not a zero price because power would add to reliability to some degree--see backup on capacity pricing to testimony of Jan Hamrin), and a relatively low price for energy. Anything cheaper than this price (i.e., that can be built at this price) is needed. Second, in our opinion, long-term QF contracts should have megawatt limits. Unlimited amounts of power should not be allowed to sign up before the price is revised. This is a lesson which we have learned in California, and a lesson which other states also appear to have learned. Long-term contracts in Connecticut have stringent limits on the number of megawatts which can sign them. One of the problems raised by Idaho Power Company was not necessarily a problem of the wrong price as much as it was a problem of too many megawatts at a price that was right for some power and no mechanism for cutting off the offer and lowering the price when the limit was reached.

Finally, utilities often plan to build plants with long lead times. As a result, they can use the short lead times of QFs, which should benefit the utility with more flexibility, against QF development if there is no long-term contract or no obligation to buy power until the exact minute that the utility needs it. A utility may be spending substantial sums of money on its next plant five years before it comes on line, at a time when it does not "need" power. Because no QFs would have signed contracts (in the absence of a long-term QF contract or if utilities were not obligated to purchase), the utility would commit to its own plant five years in advance and would never "need" the QF generation that would displace its plant. Thus, instead of encouraging generation with shorter lead times, the utility would instead be committing to longer lead time generation of its own without ever reaching the QF generation. This is the "Catch 22" which was discussed at length in Dr. Hamrin's testimony.

3. Why should utilities pay 100 percent of avoided cost?

The full avoided cost standard provides a common yardstick to measure all supply and demand options available to utilities, including conservation, QF generation, purchases from other utilities, and their own new supply options. It is therefore a very useful and reasonable standard to make available. By requiring utilities to offer full avoided cost prices to third party developers, utilities have less incentive to inflate the cost estimates of their own new plants, and regulators have a standard against which to measure the reasonableness of costs of future utility plants.

Furthermore, to the extent that QFs do not supply 100 percent of the utilities' new power sources, utilities will still have to build new plants at (or in some states which do not implement PURPA correctly, greater than) full avoided costs. In such cases, ratepayers would probably prefer QF power, even at full avoided cost to utility power. There are several reasons. First, utility capital recovery is generally front-loaded and declines over time. Utilities recover their capital expenditures faster under traditional rate-of-return regulation than capacity payments paid to QFs under the methods generally adopted by regulatory commissions (either levelization or capacity payments which increase over time). State regulatory commissions are grappling with "rate shock" caused by these front-loaded prices for new utility plants. QFs provide much less rate shock even at 100 percent of avoided cost.

The second reason why ratepayers should prefer to pay QFs 100 percent of avoided cost to paying utilities is the fundamental difference between independent producers and utilities: that independent producers are only paid if they produce power, and that they are paid a price based on the estimated value of the power rather than their individual cost of production. As a result, QFs have more incentives to reduce their production costs than do electric utilities and more incentives to operate reliably once they come on line. They cannot pass costs and risks through to ratepayers from sources such as:

1. Sunk Cost of Cancelled Plants
2. Costs of Preoperative Plant (CWIP)
3. Cost Overruns on New Plant Construction
4. Maintenance, Replacement Power, and Early Termination Costs Resulting from Plant Failure to Perform within Originally Expected Reliability or Efficiency Specifications.
5. Cost Overruns on Decommissioning or Dismantling Costs

The success of QFs in developing, financing, building, and operating new generation projects without traditional rate of return regulation in quantities sufficient to significantly affect utility resource plans is one of the major factors leading to serious consideration of deregulation of other aspects of utility generation. Under deregulation, if all sources of generation were treated the same, perhaps an avoided cost standard would be less important.

However, while deregulation may be appealing, it takes time. Utility requests to weaken PURPA, even if couched in terms of deregulation and market competition, are highly premature. Such efforts would be likely to lead to counterproductive results. If QFs are forced to compete with each other, while utilities continue to enjoy protection under traditional regulation and retain their status as monopsony buyers of electricity due to their monopoly over transmission access, utilities will retain control over the generation system, ratepayers will be ill-served, and future deregulation will only be impeded.

NWEA NATIONAL WOOD ENERGY ASSOCIATION

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ANSWERS TO QUESTIONS SUBMITTED BY
SENATOR JOHNSTON

1. "Wouldn't National energy policy be better served by requiring the electrical capacity of an oil- or gas-fired cogeneration facility to be a function of the thermal need to be served?"

   Yes, but the FERC regulations under PURPA, which define a qualifying cogeneration facility, already do require that such a facility produce a minimum amount of useful thermal energy as a proportion of its total energy input. These regulations also contain minimum efficiency standards for oil- and gas-fired cogenerators.

   Perhaps the question is whether these standards should be raised to require higher efficiency and more thermal output per unit of fuel input. By its nature, a cogeneration facility produces at least two separate products -- electric power and useful thermal energy -- and thus must respond to two different markets in an effort to remain competitive. The market for thermal energy is extremely diverse, being compromised of a wide variety of thermal energy needs. It would be very difficult to establish cogenerator operating and efficiency standards that precisely fit the thermal load characteristics of all firms in the thermal energy market.

   The market for the electric power output of cogenerators, as envisioned by PURPA, is the Nation's electric utilities. The quantity of demand for this electric power and the price to be paid for it is, likewise, difficult to establish by rule for all firms in the market for electric power. Congress and the FERC had this problem in mind when they determined that the market for cogeneration under PURPA should be defined by market forces and not by regulatory directives.

The purpose of existing minimal operating and efficiency standards for cogenerators is generically to define what a "qualifying cogeneration facility" is; there appears to be little or no basis in the statute or regulations for what would amount to a rather complex program to regulate the thermodynamic efficiency of each cogeneration facility in terms of each specific thermal load to be served.

National energy policy, as it relates to the issue of cogeneration efficiency, is probably best served by (1) adhering to a generic minimum definitional standard at the Federal level, and (2) encouraging each state agency to develop contracting and price mechanisms which reward thermodynamic efficiency in cogenerators through market mechanisms, such as heat rate-based price schedules, which require them to compete with the efficiency of existing planned utility generating units.

2. "Is there any justification for requiring utilities to buy capacity from Qualifying Facilities (QF) that the utilities do not need within their existing planning horizons?"

Yes, but the price such utilities pay should reflect their relatively low demand for such capacity. Whenever utilities purchase capacity (or energy) at a price that does not exceed their avoided cost of these products, they and their ratepayers remain economically indifferent; and the reliability of their electrical systems and their ability to conduct responsible resource planning are enhanced by the addition of any new capacity that is added to their resource base.

The important point is that avoided-cost rate-making, if done properly and effectively, dictates that if the utility needs no new capacity, its avoided cost for capacity will approach zero. If qualifying facilities are offering capacity at a price that approaches zero, the utility should be willing to purchase it. In the absence of voluntary purchases, which reflect these sound principals of competitive market economics, the utility should be required to purchase capacity at its avoided cost.

3. "What justification is there for retaining a 100-percent full avoided-cost standard?"

There are several. Perhaps the most important, however, is to ensure an optimum supply of QF electrical generation.

The full avoided-cost standard was established as an economically efficient market mechanism to dictate not only the price to be paid for QF power, but, indirectly, the supply as well. That is, the supply of QF power is impacted by the price paid for such power, and economic theory as embodied in FERC regulations dictates that the "correct" level of supply of QF power is all that is available at a price equal to the purchasing utility's full avoided costs. As discussed following Question 2, above, economic indifference as to the source of energy and capacity will be ensured when utilities purchase all the QF energy and capacity that is available at a price that does not exceed full avoided costs. If a price below full avoided costs is paid, theoretically, the supply of QF power will be less, assuming every firm is producing competitively and efficiently. Thus, less of the benefits of QF generation will be realized by the purchasing utility and its ratepayers than would otherwise be available at the full avoided cost price.

It is true that there is more qualifying facility development today than there was when FERC first established the full avoided-cost standard. There are many different reasons for this, including the fact that key sectors that impact the level of such development, such as the financial, regulatory, and engineering sectors, have had time initially to internalize the characteristics of this new market. However, it would probably be a mistake to assume that the current level of QF development is sufficient to meet the Nation's future energy needs, or is in any other way the "correct" level of development. Nor would it be wise to abandon the free market approach to qualifying facility development and the full avoided-cost standard that effectuates this approach and revert to a directed market approach which is implied by establishing a price for QF power at an inherently arbitrary discount from full avoided costs.

The fact is that the demand for electric energy and capacity in this country has not stopped growing, nor is the process of planning capital resources to meet that demand in the future any easier or more subject to control than it was when PURPA was enacted.

Dispersed independent power facilities help meet new demand at no risk to ratepayers and provide utilities with flexibility in resource planning. Moreover, when power is purchased at full avoided costs, it lowers future marginal costs for the purchasing utility as well as providing the utilities with competition for their own generating units and an associated incentive to further cut costs.

All of these benefits are important to utility ratepayers; and it is good National energy policy to maximize them through the full avoided-cost standard, which optimizes the level of qualifying facility development.

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WASHINGTON, D.C. 20036

THOMAS A. MICHELETTI
VICE PRESIDENT - WASHINGTON REGION

TELEPHONE
(202) 872-1900

July 1, 1986

Honorable James A. McClure
Chairman
Committee on Energy and Natural Resources
SD-361, U.S. Senate
Washington, D.C. 20510

Dear Mr. Chairman:

Transmitted herein is Southern California Edison Company's response to the questions submitted by Senator Johnston as a result of your Committee hearings on the implementation of the Public Utility Regulatory Policy Act of 1978. Your efforts to incorporate this response into the official record are greatly appreciated.

If you have any questions regarding this matter, please call me at 872-1900.

Sincerely,

Thomas A Micheletti

TAM:bjs

cc: Hon. J. Bennett Johnston
Michael R. Peevey

RESPONSES OF THE SOUTHERN CALIFORNIA EDISON COMPANY TO PURPA OVERSIGHT HEARING QUESTIONS SUBMITTED FOR THE RECORD FROM SENATOR J. BENNETT JOHNSTON

1. Q. The Committee heard significant testimony concerning so-called "PURPA machines" -- oil or natural gas-fired cogeneration facilities that satisfy FERC's efficiency standards but that produce more electricity and burn more fuel with less efficiency than would be the case if the facilities were sized to meet their thermal needs. Given the fact that oil and natural gas are ultimately scarce resources, wouldn't national energy policy be better served by requiring the electrical capacity of an oil or gas-fired qualifying cogeneration facility to be a function of the thermal need to be served?

1. A. PURPA clearly set forth a goal of promoting conservation and efficiency in energy use. If, in fact, this is still a significant component of national energy policy, then the FERC operating and efficiency standards for cogeneration facilities require careful reexamination. Most cogenerators do not "reduce reliance" on fossil fuels in the traditional sense by using alternative and/or renewable energy sources.

Oil and natural gas are the primary fuel sources in most cases. The benefits of true cogeneration stem instead from making more efficient use of the thermal energy produced from these sources. Genuine cogenerators make multiple uses of thermal energy, typically steam, to sequentially produce electricity and perform one or more other useful tasks (i.e. heating, cooling, etc.). The problem with the current FERC rules is that it is relatively easy to circumvent the intent of PURPA by constructing a conventional power plant to which a token secondary waste-heat use is "tacked on." As FERC specifies that only 5 percent of the cogenerator's output must be in the form of thermal energy, many cogeneration systems now employ an "extraction turbine," which allows 5 percent of the total steam to be extracted from the turbine and sent to a small heat use, while 95 percent is directed to electricity generation. Hence, electric generation is not an efficient secondary use for heat which would otherwise be wasted -- it is the paramount function of the equipment. With the 95 to 5 percent relationship, a cogenerator can now use a very small need for thermal energy to justify a power plant 19 times larger than required by this need. This sort of configuration is arguably not sequential, does not promote efficiency, and most certainly does not conserve finite fossil fuels. The

FERC 5-percent rule needs to be re-evaluated. New rules should be promulgated which mandate that cogenerators size their facilities no larger than required to efficiently meet the thermal need to be served. The requirement of sequential use should also be affirmed and enforced. If facilities are designed to meet thermal needs rather than maximize electricity production, no percentage rule is needed.

2. Q. Is there any justification for requiring utilities to buy capacity from qualifying facilities that the utilities do not need within their existing planning horizons? Doesn't this represent a net cost to consumers?

2. A. Many state regulatory commissions have mandated capacity payments to QFs even when utility capacity is projected to be high enough to serve load reliably throughout the planning horizon. This requirement is clearly contrary to the FERC rules, which require utilities to pay QFs for capacity value only when the QF allows the utility to defer construction of new plant, or defer or avoid firm power purchases.

Paying for capacity in advance of need is a direct and unnecessary economic burden on ratepayers. In fact, ratepayers bear a double burden in this situation. They must pay for capacity installed by the utility to meet their needs, and then pay an additional amount for unneeded capacity installed by QF's. This sort of PURPA implementation by state commissions clearly results in a waste of resources and harms utility ratepayers.

3. Q. What justification is there for retaining a 100 percent full avoided cost standard? If there was, for example, an 80 percent avoided cost standard, electric consumers would directly receive the savings, namely, the 20 percent difference between the utility's avoided cost and what it would be required to pay a qualifying facility. Originally, FERC considered a less-than-full avoided cost standard but rejected it because little development of qualifying facilities was expected, and encouragement of diversified power supply was thought to be more important. However, the growth of cogeneration and small power production has exceeded original expectations. In those areas where there has been extensive development of qualifying facilities, couldn't there be a provision for the payment of less-than-full avoided cost rates without discouraging further development?

3. A. The full avoided-cost standard is a flawed pricing method. It fails to recognize that QFs have different cost structures, rate of return hurdles, operating characteristics, etc., and hence are willing to supply power at various prices. The differential between the amount actually required to elicit production and the full avoided cost is a surplus which economists call "economic rent." When full avoided cost (or above, in some states) is mandated, all rents flow to the QFs -- and the ratepayers receive none. When QFs are guaranteed a full avoided-cost payment, there is no incentive for them to accept a lower negotiated price that would benefit utility customers. Under a fixed percentage approach (like the 80/20 mentioned), the ratepayer is guaranteed an economic benefit from QF development. However, it is difficult to choose the exact level of the fixed percentage which will maximize ratepayer benefits while still retaining sufficient encouragement for QF development. There are other possibilities, such as bidding or auction systems, which would similarly provide benefits for ratepayers, while removing much of the quantitative difficulty by relying on market forces to determine prices.

A true "shared savings" approach, in which the ratepayers and investors share the difference between full avoided cost and the actual price agreed upon by negotiation, offers powerful incentives for all parties to work to achieve the most economical arrangement which will still allow QF development.

APPENDIX II

Responses to Additional Committee Questions From Witnesses Appearing June 5, 1986

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

July 8, 1986

Honorable James A. McClure
Chairman, Committee on Energy
and Natural Resources
United States Senate
Washington, D. C. 20510

Dear Mr. Chairman:

Thank you for your June 13, 1986, letter pursuant to your committee's recent hearings on the implementation of the 1978 Public Utility Regulatory Policies Act (PURPA).

Enclosed are responses prepared by the Commission's staff to questions submitted for the June 5 hearing record by Senators Bumpers and Johnston.

I have also enclosed information which I promised to provide for the record in response to questions asked by Senator Evans during the hearing. The first question concerns a Senate amendment to S. 426 that would redefine "small power production facility." The second question involves a Commission decision denying a petition for a rulemaking to amend the Commission's regulations governing qualification of hydroelectric facilities for incentives under PURPA.

The responses provided for the record are submitted in my capacity as a technical staff witness and do not necessarily reflect the views of the Commission Chairman or individual Commissioners.

I hope this information is helpful to you. If I may be of further assistance, please let me krow.

Sincerely,

Lawrence R. Anderson

Lawrence R. Anderson
Director of Electric
Power Regulation

Enclosure

PURPA Oversight Hearing Questions Submitted for the Record from Senator Dale Bumpers

Q.1 Provide a breakdown of the fuel sources used in qualifying cogeneration and small power production facilities that have received certification from the Commission in each year and in total since the enactment of PURPA.

A.1 Summary Through March 31, 1986

Fuel Source	Cogeneration		Small Power Production		Total	
	No.	MW	No.	MW	No.	MW
Coal	106	5,309			106	5,309
Natural Gas	613	16,211			613	16,211
Fuel Oil	38	559			38	559
Biomass	114	2,491	336	4,108	450	6,599
Waste	27	1,760	57	1,216	84	2,976
Hydro			541	2,889	541	2,889
Wind			571	1,578	571	1,578
Geothermal			53	1,914	53	1,914
Solar			30	228	30	228
Other	20	960*	5	107	25	1,067
Total	918	27,290	1,593	12,040	2,511	39,330

* Includes nuclear and solar energy sources

A.1 - Senator Bumpers (continued)

Summary Through March 31, 1986

Fuel Source	Cogeneration		Small Power Production		Total	
Coal	No.	MW	No.	MW	No.	MW
FY80	2	13.0			2	13.0
FY81	3	634.5			3	634.5
FY82	7	261.4			7	261.4
FY83	22	931.2			22	931.2
FY84	20	970.2			20	970.2
FY85	26	1,249.4			26	1,249.4
FY86	26	1,249.2			26	1,249.2
Subtotal	106	5,309.0			106	5,309.0
Natural Gas						
FY80	4	146.2			4	146.2
FY81	10	86.6			10	86.6
FY82	42	2,170.9			42	2,170.9
FY83	75	2,257.1			75	2,257.1
FY84	110	1,883.5			110	1,883.5
FY85	182	6,262.6			182	6,262.6
FY86	190	3,403.7			190	3,403.7
Subtotal	613	16,211.0			613	16,211.0
Fuel Oil						
FY80	2	28.3			2	28.3
FY81	--	--			--	--
FY82	4	16.7			4	16.7
FY83	6	91.9			6	91.9
FY84	10	65.7			10	65.7
FY85	11	253.7			11	253.7
FY86	5	102.8			5	102.8
Subtotal	38	559.0			38	559.0
Biomass						
FY80	2	161.4	1	0.1	3	161.5
FY81	5	97.2	16	284.2	21	381.4
FY82	21	439.6	36	420.1	57	859.7
FY83	22	452.6	55	543.0	77	995.6
FY84	30	534.4	51	704.4	81	1,238.8
FY85	24	586.0	112	1,088.1	136	1,674.1
FY86	10	219.8	65	1,068.2	75	1,288.0
Subtotal	114	2,491.0	336	4,108.0	450	6,599.0

A.1 - Senator Dale Bumpers (continued)

Summary Through March 31, 1986

Fuel Source	Cogeneration		Small Power Production		Total	
Waste	No.	MW	No.	MW	No.	MW
FY80	1	75.0	1	0.5	2	75.5
FY81	--	--	--	--	--	--
FY82	2	74.3	2	29.3	4	103.6
FY83	2	228.0	6	167.5	8	395.5
FY84	7	647.9	11	110.2	18	758.1
FY85	7	207.4	17	371.4	24	578.8
FY86	8	527.2	20	536.9	28	1,064.1
Subtotal	27	1,760.0	57	1,216.0	84	2,976.0
Hydro						
FY80			10	107.8	10	107.8
FY81			9	39.3	9	39.3
FY82			29	63.4	29	63.4
FY83			89	396.9	89	396.9
FY84			112	369.2	112	369.2
FY85			82	305.0	82	305.0
FY86			210	1,607.1	210	1,607.1
Subtotal			541	2,889.0	541	2,889.0
Wind						
FY80			4	76.0	4	76.0
FY81			20	23.8	20	23.8
FY82			56	126.6	56	126.6
FY83			127	325.0	127	325.0
FY84			109	270.3	109	270.3
FY85			224	607.8	224	607.8
FY86			31	148.3	31	148.3
Subtotal			571	1,578.0	571	1,578.0
Geothermal						
FY80			1	76.0	1	76.0
FY81			1	80.0	1	80.0
FY82			3	73.5	3	73.5
FY83			8	119.0	8	119.0
FY84			9	168.1	9	168.1
FY85			7	164.1	7	164.1
FY86			24	1,233.0	24	1,233.0
Subtotal			53	1,914.0	53	1,914.0

A.1 - Senator Dale Bumpers (continued)

Summary Through March 31, 1986

Fuel Source	Cogeneration		Small Power Production		Total	
Solar	No.	MW	No.	MW	No.	MW
FY80			--	--	--	--
FY81			--	--	--	--
FY82			4	0.2	4	0.2
FY83			5	91.6	5	91.6
FY84			5	94.3	5	94.3
FY85			12	42.4	12	42.4
FY86			4	0.1	4	0.1
Subtotal			30	228.0	30	228.0
Other						
FY80	1	19.5	--	--	1	19.5
FY81	3	60.3	1	13.0	4	73.3
FY82	2	568.8	--	--	2	568.8
FY83	3	15.4	2	67.8	5	83.2
FY84	5	69.4	--	--	5	69.4
FY85	4	127.9	--	--	4	127.9
FY86	2	98.9	2	26.0	4	124.9
Subtotal	20	960.0*	5	107.0	25	1,067.0
Total						
FY80	12	443.4	17	260.4	29	703.8
FY81	21	878.6	47	440.3	68	1,318.9
FY82	78	3,531.7	130	713.0	208	4,244.7
FY83	130	3,976.3	292	1,710.8	422	5,687.1
FY84	182	4,171.0	297	1,716.6	479	5,887.6
FY85	254	8,687.0	454	2,578.9	708	11,265.9
FY86	241	5,601.7	356	4,619.6	597	10,221.3
Subtotal	918	27,290.0	1,593	12,040.0	2,511	39,330.0

* Includes nuclear and solar energy sources.

Senator Dale Bumpers

Q.2 What are the obstacles to the use of coal in PURPA qualifying facilities? Please discuss. How could PURPA or the regulations under PURPA be modified to encourage increased use of coal in qualifying facilities?

A.2 There appear to be several obstacles to the use of coal in qualifying facilities.

Capital costs and pollution control requirements are significant economic obstacles. The construction costs of coal-fired electric generating facilities are generally higher than natural gas- or oil-fired facilities of comparable electrical output. This results from requirements for coal handling, storage and pulverizing equipment; larger boiler facilities; ash disposal and storage facilities; and environmental control equipment to minimize particulate and nitrogen oxide emissions. If low-sulfur coal is not available or fluidized bed combustion is not used, environmental equipment must be installed so that sulfur dioxide emissions are constrained to the lower of state, local, or Federal limits. Because coal-fired generation facilities are more capital intensive, pending tax change proposals (elimination of the investment tax credit and lengthening of depreciation periods) may impact the use of coal in cogeneration facilities more than oil- or gas-fired facilities.

Commission criteria for qualification as an oil- or natural gas-fired topping-cycle cogeneration facility 1/

1/ A "topping cycle" cogeneration facility is one in which the thermal energy that results from the production of electricity is recovered and used for an industrial, commercial, heating or cooling purpose.

A.2 - Senator Bumpers (continued)

requires that the facility meet, on an annual basis, both an operating and an efficiency standard. 2/ In contrast, coal-fired cogeneration facilities are required only to satisfy the operating standard. Therefore, with respect to the Commission's qualifying criteria, coal-fired cogeneration facilities may be considered to have an advantage in that no efficiency standard is applied.

There does not appear to be any way to modify the regulations under PURPA as currently enacted to encourage further the development of coal-fired cogeneration facilities without relaxing the operating standard for these facilities. The purpose of the operating standard is to distinguish bona fide cogeneration facilities from essentially single purpose facilities that produce only trivial amounts of useful thermal energy. To relax the existing standard would tend to blur that distinction, which must be maintained to comply with the statutory definition of "qualifying cogeneration facility" in section 210(d) of PURPA and section 3(18) of the Federal Power Act.

It may be feasible to amend PURPA to permit qualifying small power producer status for coal-fired facilities.

2/ See 18 C.F.R. § 292.205(a). The operating standard establishes the minimum amount of the facility's total energy output that must be useful thermal energy. The efficiency standard establishes the minimum requirement for the percentages of useful electrical and thermal energy produced by the facility in relation to the fuel energy (oil or natural gas) put in to the facility.

A. 2 - Senator Bumpers (continued)

However, a primary purpose of PURPA was to encourage fossil fuel power production only in the cogeneration context because of the energy conserving characteristic of sequential use of the energy released by burning the fossil fuel. It should be noted that the Commission has certified as small power production facilities those using non-commercially valuable, by-product coal mine residues, such as anthracite culm, categorized as "waste" for use in small power production facilities. 3/ Also, fossil fuels, including coal, may be used for up to 25 percent of a small power production facility's annual energy input to supplement other, non-fossil fuels.

3/ Electrodyne Research Corporation, 32 FERC ¶ 61,102 (1985).

Senator Dale Bumpers

Q.3 Currently there is a size limit of 30 megawatts for qualifying small power production facilities that seek certain exemptions under PURPA. Should this limit be increased or eliminated? What effect would elimination of the limit have?

A.3 Under section 210(e) of PURPA, the Commission is authorized to exempt certain qualifying facilities from all or part of the Federal Power Act, the Public Utility Holding Company Act, and certain state laws and regulation. The Commission has used this authority to exempt such facilities from utility-type regulation that would be a disincentive to small power production and cogeneration. The Commission's regulations extend these exemptions to all qualifying facilities for which exemptions are authorized under section 210(e), including all cogeneration facilities, all geothermal small power production facilities, all biomass small power production facilities, and all other small power production facilities with generating capacity of 30 MW or less. Section 210(e) does not permit exemptions for non-geothermal and non-biomass small power production facilities with capacity over 30 MW. The Commission has no position regarding whether the exclusion from the exemption for those facilities should be changed.

A small percentage of the qualifying small power production facilities (SPPF) are not eligible for the regulatory exemption of section 210(e) because of their electric power production capacity. Of the 1,593 qualifying SPPF filings received through March 31, 1986, only 148 facilities were larger than 30 MW. Ten of these facilities also were qualifying

A.3 - Senator Bumpers (continued)

cogeneration facilities and therefore eligible for the exemption in any event. Thirty-three of these facilities used geothermal fluids as their primary energy source and therefore were also eligible for the exemption. Thus, only 115 (7.2%) of the total small power production facilities were not eligible for the exemption.

If the 30 MW limit to the regulatory exemption for small power production facilities were lifted, the effect might be to encourage development of more small power production facilities larger than 30 MW. It appears that several fossil fuel facilities larger than 30 MW have been designed to include cogeneration applications that barely meet the operating and efficiency standards, for the purpose of avoiding the regulatory burdens associated with small power production facilities over 30 MW. It also appears that many small power production facilities have been designed with power outputs just below 30 MW, notwithstanding the sacrifice of some efficiency, to avoid the regulatory consequences of being over 30 MW.

For those non-exempt facilities, the Commission has reduced the burden of compliance with the Federal Power Act, which it administers. In Resources Recovery (Dade County), Inc., 20 FERC ¶ 61,138 (1982), the Commission recognized the need to present as few regulatory impediments as possible to encourage cogeneration and small power production; for these non-exempt facilities, it waived cost-of-service data requirements and relaxed certain of the Commission's filing requirements regarding property dispositions and consolidations, issuance of securities, and interlocking positions.

Senator Dale Bumpers

Q.4 What are the best estimates of the amount of electricity that will be supplied in the U.S. as a whole and regionally from cogeneration and small power production over the next three years? five years? ten years? fifteen years?

A.4 There is limited information available on existing and projected future capacity and energy associated with cogeneration and small power production facilities (QFs). The basis used for projections that are available and the type of survey conducted to determine the existing capacity of QFs often lead to different results. A study by TRW Corp., 1/ as affirmed in a 1984 survey by National Economic Research Associates (NERA), 2/ estimated that there were approximately 6,300 MW of cogeneration and 250 MW of small power production operating in the U. S. at the time of PURPA enactment in 1978. 3/ The most recent studies of future cogeneration capacity were published in 1984 by Hagler, Bailly & Company (H, B & Co.), and Dun and Bradstreet 4/ and in 1985 by Frost and Sullivan. 5/

1/ TRW, Energy and Environmental Division, Analysis of Existing Industrial Cogeneration Capacity, Washington (1982).

2/ National Economic Research Associates (NERA), Pre- and Post-PURPA Development of Cogeneration and Small Power Projects, unpublished paper (November 1984).

3/ The NERA survey does not include results for several large utilities which failed to respond to the request for data on QF development.

4/ Hagler, Bailly & Company, U.S. Industrial Cogeneration: Market Prospects for Process Steam and Electricity Cogeneration Systems, Washington (1984).

Dun and Bradstreet Technical Economic Services and TRW Energy Development Group, Industrial Cogeneration Potential (1980-2000), report prepared for the U.S. Department of Energy (August 1984).

5/ Frost & Sullivan, The Industrial/Commercial Cogeneration Systems and Service Market in the U.S., Report No. A1442 (April 1985).

A.4 - Senator Bumpers (continued)

The H, B & Co. study concluded that cogeneration capacity in the U. S. can be expected to grow from a 1983 level of about 11,000 MW to 26,000 MW by 1995, with more than half of the new capacity located in Texas and Louisiana. These numbers reflect both pre- and post-PURPA QF development.

The Dun and Bradstreet/TRW report indicates a potential of approximately 39,350 MW of industrial cogeneration capacity for the same period. However, this study does not factor in potential obstacles such as market saturation and declining avoided cost rates in certain states.

An unpublished 1985 Commission staff paper indicated that in 1980, electric generation by non-utilities was approximately 3 percent of the national total. This paper, completed prior to proposal of the pending changes in the tax laws, predicted that, under the impetus of PURPA and other incentives (i.e, tax benefits), nearly one-half of the generating capacity additions between 1985 and 1995 could be by non-utilities; in 1995, non-utility generation could represent more than 10 percent of the national electric generation. Due to a number of uncertainties, such as the price of oil and gas, continuation of tax benefits, successful commercial development of small fully-automated cogeneration facilities for power/ heating/cooling package installations, and declining avoided costs in certain states, the paper provided a range of forecasts of capacity growth under low, medium and high capacity growth scenarios (see table below).

A.4 - Senator Bumpers (continued)

Table 1

Utility and Non-Utility Capacity Growth

	1984 Installed Capacity (MW)	Projected Additions to 1995 (MW)	1995 Projected Installed Capacity (MW)
Utilities	665,000 (DOE)	110,000 (a)	775,000 (a)
		104,000 (b)	769,000 (b)
		88,000 (c)	753,000 (c)
Non-Utilities	15,000 (Est.)	12,000 (a)	27,000 (a)
		25,000 (b)	40,000 (b)
		55,000 (c)	70,000 (c)
Total	680,000	122,000 (a)	802,000 (a)
		129,000 (b)	809,000 (b)
		143,000 (c)	823,000 (c)

(a) Base Case. Present utility projections with low non-utility generation growth

(b) Medium growth of non-utility generation

(c) High growth of non-utility generation

In (b) and (c) utility additions are assumed to be reduced by one-half the difference between non-utility additions and the base case.

PURPA Oversight Hearing Questions Submitted for the Record
from Senator J. Bennett Johnston

Q.1 The Committee heard significant testimony concerning so-called "PURPA machines" -- oil or natural gas-fired cogeneration facilities that satisfy FERC's efficiency standards but that produce more electricity and burn more fuel with less efficiency than would be the case if the facilities were sized to meet their thermal needs. Given the fact that oil and natural gas are ultimately scarce resources, wouldn't national energy policy be better served by requiring the electricity capacity of an oil or gas-fired qualifying cogeneration facility to be a function of the thermal need to be served?

A.1 Strictly speaking, the electric capacity of a cogeneration facility is always a function of the thermal need because production of electricity in a cogeneration facility requires the use of thermal energy. Thus, it is assumed that the question is intended to ask whether national energy policy would be better served by requiring oil- or gas-fired cogeneration facilities to be designed to most efficiently meet the non-electric thermal need rather than the electrical generating function.

The national energy policy embodied in section 210 of PURPA is to encourage cogeneration and small power production facilities. The underlying rationale with regard to cogeneration facilities is that they use fuel more efficiently by using heat sequentially than would a non-cogenerating electric generating plant. Arguably, the goal of fuel efficiency would be better served by designing facilities to meet most efficiently the non-electric generating thermal need, because fuel would be used more efficiently. However, such a requirement could make these facilities less attractive financially and could result in lower electrical output. Such results would be inconsistent with the overall goal of encouraging cogeneration facilities. In essence, there is a trade-off between maximizing fuel efficiency and maximizing encouragement of facilities.

The Commission's rules, at 18 C.F.R. § 292.205(a), attempt to strike a balance by requiring that at least five percent of the total output of all topping-cycle cogeneration facilities be applied to the non-electrical thermal energy use ("five percent operating standard"). While no definitive statistics have been compiled, an informal staff survey indicates that the majority of the filings have applied more than 15 percent of the total energy input to the useful thermal output. In addition, for any topping-cycle facility for which any of the energy input is natural gas or oil, and which was installed on or after March 13, 1980, an efficiency standard applies, requiring that the total useful energy (electrical and thermal) produced by the facility be at least a certain percentage of the facility's energy consumption.

Senator J. Bennett Johnston

Q.2 Is there any justification for requiring utilities to buy capacity from qualifying facilities that the utilities do not need within their existing planning horizons? Doesn't this represent a net cost to consumers?

A.2 Section 210 of the PURPA requires electric utilities to purchase energy and capacity from qualifying facilities. Section 292.303 of the Commission's regulations implementing section 210 requires electric utilities to purchase capacity even if it is not needed. Notwithstanding this provision, a utility's customers should be no worse off financially than they would have been without the purchase from the qualifying facility, because of the operation of the Commission's avoided cost rule. Under that rule, utilities that cannot avoid any capacity costs by purchases from qualifying facilities are required to pay only avoided energy costs (i.e., the avoided fuel and operating costs). See 18 C.F.R. § 292.304. Thus, under a properly designed avoided cost rate under the Commission's regulations, a utility should not have to pay more than the costs that are avoided by purchases from the qualifying facility.

However, a state commission, acting under authority granted by the state, may establish a purchase rate exceeding avoided cost, or a non-regulated utility may choose to pay a rate exceeding avoided cost. Where that is done, it would represent a "net cost to consumers." A possible justification for a state to require purchase rates above avoided cost would be to provide encouragement to qualifying facilities greater than that provided under the Federal rules. However, the Commission has no specific knowledge with regard to any state's policy in this matter.

Senator J. Bennett Johnston

Q.3 What justification is there for retaining a 100 percent full avoided cost standard? If there was, for example, an 80 percent avoided cost standard, electric consumers would directly receive the savings, namely, the 20 percent difference between the utility's avoided cost and what it would be required to pay a qualifying facility. Originally, FERC considered a less-than-full avoided cost standard but rejected it because little development of qualifying facilities was expected, and encouragement of a diversified power supply was thought to be more important. However, the growth of cogeneration and small power production has exceeded original expectations. In those areas where there has been extensive development of qualifying facilities, couldn't there be a provision for the payment of less-than-full avoided cost rates without discouraging further development?

A.3 Congress directed the Commission to encourage cogeneration and small power production facilities. Establishing full avoided cost as the rate for purchase from qualifying facilities gives those facilities maximum encouragement through pricing, without adversely affecting the utility's native load customers. At the time these regulations were promulgated, the Commission noted in the preamble to its avoided cost rules, 45 Fed. Reg. 12214, 12222 (February 25, 1980), that, in most instances, if part of the savings from cogeneration and small power production were allocated among the utility's ratepayers, any rate reductions would be insignificant for any individual customer. The Commission also noted that allocating these savings to the relatively small class of qualifying facilities would provide a significant incentive for growth of these technologies. This logic would be equally applicable today.

It is reasonable to assume that any purchase rate below full avoided cost will inevitably discourage some qualifying

A.3 - Senator Johnston (continued)

facility development, simply because the return on investment would be decreased. However, the Commission has little data regarding the construction and operation of qualifying facilities or the avoided cost prices paid by utilities. Thus, the degree to which purchase price reductions would affect the level of development cannot be estimated.

In addition, under a properly applied full avoided cost rule, the utility and its customers are in the same position they would have been without the purchase because, by definition, the avoided cost is limited to the cost the utility otherwise would have paid to generate the electricity itself or purchase it from another source (see response to question 2).

It should also be noted that avoided cost rates are fallback rates under the Commission's PURPA implementation regulations. Utilities and qualifying facilities have the right to negotiate any mutually agreeable purchase rate. Although statistical data is not available, the Commission is aware that many qualifying facility power purchase contracts are negotiated at rates lower than full avoided cost. In these cases, the utility and its customers share the savings provided by purchases from the qualifying facility. Thus, there is an apparent basis for continuation of the rule.

The Commission's rules provide for procedures by which a person may seek to amend the Commission's regulations. However, while there have been anecdotal indications of dissatisfaction with the full avoided cost rules, no utility, state commission or non-regulated utility has requested that the Commission amend these rules.

RESPONSE TO SENATOR EVANS
(Request for general view of the provisions
of sections 10 and 11 of S. 426)

Sections 10 and 11 of S. 426 place restrictions on eligibility for certain benefits for hydroelectric projects under section 210 of the Public Utility Regulatory Policies Act (PURPA). Section 210 provides three important benefits as incentives to small power production: a secure source of energy from electric utilities; a guaranteed market for the power produced at the small power production facility at rates up to the cost the buying electric utility would have incurred to generate the power or purchase it elsewhere; and, in some cases, an exemption from certain Federal and state regulation.

Sections 10 and 11 of S. 426 would make all the benefits of section 210 of PURPA available only to hydroelectric projects built at existing dams or diversions and to those built at new dams or diversions if the dam is owned by the government or if the project meets environmental requirements imposed by Federal and state fish and wildlife agencies. Hydroelectric projects at new dams or diversions that did not meet these criteria, but were otherwise qualified as small power production facilities, would be eligible for the regulatory exemption. However, the guaranteed energy and market benefits of section 210 would not be available to those projects.

These provisions raise the following concerns regarding implementation.

First, projects that are exempt from the Commission's licensing requirements under section 405 of PURPA or section 30 of the Federal Power Act are required under existing law to meet the identical environmental requirements set forth in section 10 of the bill for new dam or diversion projects to qualify for PURPA section 210 benefits. The committee report notes this and states it is not the intention of the committee that section 10 apply to such projects. However, the proposed statutory language does not specifically exclude exemption projects; and since licensing or exemption procedures are separate from procedures establishing qualifying status for PURPA small power production benefits, the developer seeking qualifying facility ("QF") status for an exemption project at a new dam or diversion might be required, under a literal reading of section 10, to make two separate showings of compliance with the identical requirements.

It is not clear how a project is to demonstrate that it "meets terms and conditions set by fish and wildlife agencies" at the stage at which QF status is sought. For many lenders, certification of QF status is a prerequisite to approval of financing for a project. Obtaining QF certification early in the process, before construction begins, is therefore critical to many developers. However, if section 10 requires that the developer demonstrate that it has carried out the agencies' terms and conditions, it seems unlikely that QF status could be determined until the project was completed and in operation. This could result in a circular situation in which a developer could not get QF certification until the project was built, but could not build the project without QF certification.

This ambiguity also raises a question regarding enforcement and implementation of the section 10 requirement. The committee report states that the fish and wildlife agencies' terms and conditions would not constitute terms and conditions of the license for the project, but rather would be prerequisites for new dams and diversions to receive the PURPA energy and market benefits. (No express provision on this point is found in the bill, however.) If the fish and wildlife agencies establish terms and conditions that require ongoing compliance by the project, it is unclear what mechanism is to assure that a project which "meets" the terms and conditions for purposes of obtaining QF certification will continue to comply.

The environmental requirements proposed in section 10 for new dams and diversions raise two issues relating to the efficient administration of the QF certification process. It is important to recognize that a key component of the Commission's QF program is the ability of a facility that meets the various tests for qualifying status to self-certify the project under 18 C.F.R. § 292.207. Given the tremendous volume of projects seeking the benefits of QF status, this procedure allows for significant expedition of the process, particularly in non-controversial cases. Separate environmental evaluation at the certification stage, as proposed in section 10, would preclude many potential hydroelectric QF facilities from self-certification. There may, in turn, be no resulting benefit, since environmental concerns, in any event, will be addressed adequately at the licensing or exemption stage for these self-certified QFs; thus, no sacrifice of environmental protection arises from the self-certification process. Under the requirements proposed by section 10, the Commission would have to make a QF determination for each of these projects, which could create new delays for all QF certifications. Delays in certification in the past have jeopardized financing for some QF applicants, and the new delays that would be created by section 10 could make obtaining financing more difficult.

The environmental requirements under section 10 would be parallel, but not necessarily identical, to those that must be met before a license can be issued. As a result, this provision would subject licensing proceedings to two different methods of environmental review, depending on whether QF certification were desired. If the developer's decision whether to seek QF status were not made before the license processing had begun, administrative effort could be wasted. Moreover, environmental terms and conditions imposed in a license by the Commission may differ from those required by the fish and wildlife agencies for QF status. This might create a dilemma for a developer if the terms and conditions required by the Commission could not be reconciled with those required by the fish and wildlife agencies.

[¶ 61,322]

Qualifying Facility Status for Hydroelectric Projects under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978, Docket No. RM83-69-002

Order Denying Rehearing

(Issued March 6, 1986)

Before Commissioners: Anthony G. Sousa, Acting Chairman; Charles G. Stalon, Charles A. Trabandt and C. M. Naeve.

I. Introduction

The Federal Energy Regulatory Commission (Commission) is denying rehearing of an order denying a petition for rulemaking [1] filed by several environmental groups. [2] Petitioners had requested the Commission to reopen a prior rulemaking proceeding, [3] in order to prepare a programmatic environmental impact statement (EIS) for that rulemaking, and to amend the Commission's rules governing qualification of certain hydroelectric facilities for incentives under sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) [4] and the Commission's regulations promulgated thereunder. Under the existing rules, certain hydroelectric facilities are eligible for qualifying facility (QF) status, and thus the incentives available to such facilities under the Commission's regulations, without regard to whether the facilty is already existing (old) or is proposed to be built in the future (new).

Petitioners contend that rehearing should be granted for three reasons. First, the Commission did not reconsider whether the existing rule is consistent with the intent of PURPA, as expressed in the legislative history. Second, the Commission violated the National Environmental Policy Act (NEPA) [5] by not undertaking a new, programmatic environmental review of the existing rule, in light of increased hydroelectric development activity after the rule was promulgated. Finally, the Commission abused its discretion by not reexamining the existing rule in light of new information showing that it was based on erroneous assumptions or information.

The Commission is denying rehearing because it is not persuaded that its prior order was incorrect and because the Commission believes that it is fully in compliance with its obligations under both PURPA and NEPA.

II. Discussion

A. Petitioners' Argument that Permitting QF Status for New Dams and Diversions Violates PURPA

Petitioners' first argument is that in enacting PURPA, Congress barred the Commission from granting QF status to new hydroelectric facilities. As the Commission noted in the order of January 8, 1986, Petitioners had an opportunity to request rehearing of the final rule and failed to do so. [6] Thus, for the reasons set forth in the order of January 8, 1986, the Commission again rejects Petitioners' request to reopen Docket No. RM79-54 on this ground.

B. Whether a New or Supplemental Programmatic Review of the PURPA Rules Is Required at This Time

Petitioners appear to have abandoned their claim that the Commission is not monitoring the environmental impacts of new, PURPA-induced hydroelectric projects. However, they continue to assert that a new, programmatic environmental assessment of the effects of permitting QF status for new facilities needs to be made at this time. We construe Petitioners' fundamental premise to be that such a review must be undertaken because new information has come to light indicating either that the original Environmental Assessment (EA) [7] conducted at the time the PURPA rules were promulgated was not valid or, if the EA was valid when conducted, circumstances have changed to such a degree that its conclusions are no longer valid.

The Commission acknowledges that the number of license and exemption applications has increased sooner than was anticipated in the EA. The Commission continues to believe, however, that this fact alone does not call into question the validity of the approach to further environmental review taken in the EA, [8] and does not constitute sufficient reason to compel a new, programmatic review of the PURPA rules at this time.

In this regard, the Commission reiterates that the fact that a license is issued for a hydroelectric project is not a guarantee that it will be built. A licensee's decision regarding whether to construct a project or to seek to surrender the license rests largely on economic factors. Thus, a hydroelectric QF developer may find, after having acquired the license, that its avoided cost projections were overstated, and that the project has become uneconomic. A downward trend in avoided cost rates (as discussed in the following paragraph) could result in many licensed projects being abandoned prior to construction. [9]

The Commission also believes there is good reason to think that recent increases in hydroelectric applications will abate substantially for the foreseeable future. First, the Federal energy tax credit applicable to, *inter alia*, hydroelectric QFs, expired on December 31, 1985. Moreover, avoided cost rates for purchases from QFs, as determined by the state regulatory authorities, have generally been declining over the past year. [10] This trend has been particularly evident in some states with significant hydropower potential. [11] From these developments, a decline in the number of hydroelectric applications might be expected. Thus, the Commission continues to adhere to its conclusion that sufficient cause has not been shown to warrant a new, programmatic review at this time.

Also with regard to preclusion of alternatives, Petitioners allege that the Commission erred legally and factually in holding, in the order of January 8, 1986, that the rule permitting QF status for new facilities has not resulted in an "irretrievable commitment" of resources which would preclude alternatives. With regard to the alleged factual error, Petitioners claim that promulgation of the rule has resulted in the commitment of substantial amounts of money to develop PURPA-induced hydroelectric projects.

The Commission believes that Petitioners have misapplied the "irretrievable commitment of resources" principle. That principle relates to the timing of environmental review *before* an agency takes action; that is, the agency must undertake its environmental review before making critical decisions which may result in the commitment of resources to action which will significantly affect the environment. [12] The Commission undertook such review at the time of its original rulemaking. In any event, as the prior order explained, obtaining QF status does not require a commitment of resources by the Commission or any other party, nor does it obviate the need for, or determine the outcome of, a hydroelectric licensing or exemption proceeding. All concerned parties have exactly the same options after QF status is obtained as before. [13]

Petitioners nonetheless contend that case-by-case review of hydroelectric applications and the Cumulative Impact Assessment Procedure (CIAP) is not adequate, on the ground that hydroelectric QF development may have environmental consequences extending beyond the river or watershed where any given project is located and that such consequences cannot be considered in the context of individual proceedings or the CIAP program. The Commission does not agree with this assertion. The Commission is not precluded from considering broad-based environmental concerns in individual license proceedings or in the CIAP program, where such consideration is appropriate. For instance, an intervenor in a hydroelectric proceeding might adduce evidence to support its belief that a particular project or group of projects would endanger the Nation's supply of whitewater rafting sites, or would threaten anadromous fisheries stocks in the Pacific Northwest, or might eliminate a critical habitat for an endangered species. The hydropower licensing or exemption procedures provide an ample forum for such concerns to be addressed.

Petitioners originally charged that the Commission has not abided by its pledge to continue monitoring the market penetration of technologies that qualify for PURPA benefits. On rehearing, they have abandoned this claim. Instead, they assert that the Commission's comprehensive PURPA implementation study is not enough. However, this assertion is based on the incorrect premise that continued environmental review in hydroelectric license and exemption proceedings and the CIAP does not provide a forum to address their concerns. It is further premised on their belief that the few, generalized facts set forth in their pleadings regarding increased hydroelectric license applications demonstrate that alternatives are fast being foreclosed. As set forth above and in the order of January 8, 1986, the Commission concludes that Petitioners' alarm is unwarranted.

There are additional reasons why a new, programmatic review of the PURPA regulations is not appropriate at this time. A programmatic review would necessarily be very general in nature and somewhat speculative. A much better way to evaluate the types of concerns raised by the Petitioners, such as the effects of water flow levels on aquatic life, is in the context of concrete project proposals that would, if built, affect identified areas in specific ways. For example, the effects on a given river of a single small facility may be quite different than the effects of half a dozen like facilities on the same river. A five megawatt facility on River A might have little or no impact on other resource values, while the same size facility on River B might have significant impacts. A facility at one site on a river may have substantially different effects than a similarly sized facility twenty miles upstream. Some facilities may be detrimental to other resource values, while other facilities enhance them. In short, each situation is unique, and the general information gathered in a programmatic review is very likely to be too abstract to significantly assist the Commission in determining whether licenses should be granted or denied, and if granted, what mitigative conditions are appropriate.

The Commission also concludes that contemplation of a new, programmatic review prior to completion of the PURPA implementation study would be unwarranted. That study, which was undertaken specifically for environmental monitoring purposes, should yield detailed and accurate information about the location, size, and construction status of PURPA-induced hydroelectric facilities. Until this information is gathered and evaluated, the true extent of market penetration will not be fully known.

The Commission believes that such specific information, as opposed to simple references to the numbers of license applications, is essential to determining whether any change in the existing rules should be proposed. To commit the substantial amount of scarce Commission resources necessary for a new, programmatic review of the regulations before this information is available seems, therefore, hasty and may be wasteful. In this connection, the Commission notes that the implementation study is proceeding on schedule and will be completed in a matter of months.

In addition, a new programmatic review now would, to some extent, duplicate the consideration of potential for cumulative impacts now taking place in the CIAP, and the activities of the PURPA implementation study. The Commission believes the most prudent use of its resources is to minimize the potential for duplicative or parallel procedures. If, upon review of the CIAP experience, the PURPA implementation study, and such other information as may come to light, the Commission concludes that further programmatic review of the PURPA rules is warranted, the Commission can use relevant data from those other sources in that review.

For the reasons set forth above and in the order of January 8, 1986, the Commission continues to believe that a new, programmatic review of the PURPA regulations as they pertain to QF status for new hydroelectric facilities is not warranted at this time. Petitioners' request for rehearing is, therefore, denied.

— Footnotes —

[1] "Qualifying Facility Status for Hydroelectric Projects under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978," 34 FERC ¶ 61,008.

[2] Petitioners are The Sierra Club, Friends of the River Foundation, National Wildlife Federation, California Trout, the Planning and Conservation League, Western River Guides Association, Friends of the Earth, The Wilderness Society, Natural Resources Council of Maine, and the American Wilderness Society.

[3] Small Power Production and Cogeneration Facilities—Qualifying Status, 45 Fed. Reg. 17,959 (March 20, 1980) (Order No. 70) (Docket No. RM79-54) (issued March 13, 1980) [*FERC Statutes and Regulations, Regulations Preambles 1977-1981* ¶ 30,134].

[4] 16 U.S.C. §§ 796, 824a-3 (1982).

[5] 42 U.S.C. §§ 4321-4361 (1982).

[6] Petitioners state that they did not file a petition for rehearing of the final rule because the rule, on its face, was neutral on the question of the eligibility of new facilities. Request for Rehearing, p. 2. However, in their petition, Petitioners acknowledged that they were aware that section 292.204 permits new facilities to have qualifying status, and stated that they chose not to challenge the Commission's interpretation of renewable resources because the Commission had pledged to monitor the effects of the rule. Petition for Rulemaking, p. 17.

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[7] Small Power Production and Cogeneration Facilities—Environmental Findings; No Significant Impact and Notice of Intent to Prepare Environmental Impact Statement, 45 Fed. Reg. 23,661 (April 8, 1980) (10 FERC ¶ 61,314) (March 31, 1980).

[8] In the EA, the Commission stated that it would continue to monitor the market penetration of technologies that qualify for PURPA benefits (45 Fed. Reg. at 17,965) and that any significant impacts caused by PURPA-induced hydroelectric development would be evaluated and subjected to mitigation measures in the traditional manner; that is, in hydroelectric license and exemption proceedings.

[9] As noted below at page 10, the Commission expects to have more specific information in this regard in a matter of months.

[10] *See* "Electric Utility Week," McGraw-Hill, February 17, 1986, p. 15; "Cogeneration Report," McGraw-Hill, February 14, 1986, p., 1; January 31, 1986, p. 3; January 17, 1986, p. 1; December 6, 1985, p. 5; August 16, 1985, p. 6; May 24, 1985, p. 1; "Cogeneration," Pequot Publishing, Nov.-Dec. 1985, p. 6.

[11] "Cogeneration Report," McGraw-Hill, May 24, 1985, p. 5; April 26, 1985, p. 1, February 1, 1985, p. 4; January 18, 1985, p. 3; January 4, 1985, pp. 1, 3; "Electric Utility Week," McGraw-Hill, January 6, 1986, p. 14, November 4, 1985, p. 13, September 16, 1985, p. 12; August 26, 1985, p. 10.

[12] *See Mobil Oil Corp. v. FTC*, 562 F.2d 170, 173 (2d Cir. 1977) and *American Public Transit Association v. Goldschmidt*, 485 F. Supp. 811 (D.D.C. 1980). Petitioners characterize this principle as "FERC's . . . test" and state that it is "not legally correct." Request for Rehearing, p. 15. However, the requirement to consider any irreversible commitment of resources that would result from the proposed action appears in NEPA itself. 42 U.S.C. § 4332(2)(c)(v).

[13] 34 FERC at p. 61,008.

[¶ 61,008]

Qualifying Facility Status for Hydroelectric Projects Under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978, Docket No. RM83-69-000

Order Denying Petition for Rulemaking

(Issued January 8, 1986)

Before Commissioners: Raymond J. O'Connor, Chairman; A. G. Sousa, Charles G. Stalon, Charles A. Trabandt and C. M. Naeve.

I. Introduction

The Federal Energy Regulatory Commission (Commission) is denying a petition for rulemaking filed by several environmental groups. [1]

Petitioners request that the Commission reopen a prior rulemaking proceeding, [2] in order to prepare a programmatic environmental impact statement for that rulemaking and amend the Commission's regulations governing qualification for certain incentives for hydroelectric facilities. Order No. 70 established, *inter alia*, criteria and procedures [3] to determine whether certain hydroelectric facilities qualify for benefits under sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). [4] Petitioners believe that their proposed amendments to the regulations would be preferable from an environmental standpoint and more consistent with the intent of PURPA.

The Commission is denying the petition because it is not persuaded that its prior interpretation and implementation of sections 201 and 210 of PURPA in Order No. 70 was incorrect, and because the Commission believes that its existing approach to consideration of environmental implications of hydroelectric qualifying facilities (QFs) is preferable to Petitioners' proposed alternatives.

II. Background

Section 201 of PURPA requires the Commission to issue rules under which small power production and cogeneration facilities can obtain qualifying status. [5] Qualifying status exempts a facility from regulation under certain provisions of the Federal Power Act (FPA), [6] from regulation under the Public Utility Holding Company Act of 1935, [7] and from certain state laws and regulations pertaining to the regulation of electric utilities. Additionally, utilities must purchase electricity from qualifying facilities at a rate not to exceed the "avoided cost" of generation to the utility. A QF is also entitled to retail electric service on a non-discriminatory basis.

During the rulemaking proceedings to implement sections 201 and 210 of PURPA, the Commission prepared an Environmental Assessment (EA) [8] under the National Environmental Policy Act of 1969 (NEPA). [9] Based on data developed in the EA, the

63-531 0 - 86 - 29

Commission determined that any significant environmental impact that would occur due to an increase in development of hydroelectric projects caused by allowing qualifying status for such projects could best be dealt with on a case-by-case basis, as individual applications to develop and operate projects are filed with the Commission.[10]

Petitioners did not file a petition for rehearing of the final rule. Three years later, on May 16, 1983, Petitioners filed their petition for rulemaking. On August 3, 1984, Petitioners filed a request for rehearing of what they characterized as a *"de facto"* denial of their petition and a request for expedited action. On April 10, 1985, no action having yet been taken by the Commission on the petition, several of the Petitioners brought an action in the United States Court of Appeals for the Ninth Circuit, alleging that the Commission had unreasonably delayed action on the rulemaking petition and that such inaction represented a *de facto* denial of the petition.[11] Petitioners requested that the court order the Commission to reevaluate and amend its regulations permitting QF status for new hydroelectric facilities and to stay those regulations pending a reevaluation.

By order dated December 12, 1985, the court remanded the record at the Commission's request to enable the Commission to issue this order acting on the petition within 90 days. By order dated December 18, 1985, the court remanded also to the Commission Petitioners' request for a stay of the application of the QF regulations to new hydroelectric facilities, with the direction that lack of Commission action within 21 days (January 8, 1986) would be considered a denial of the request. On December 31, 1985, the American Paper Institute filed a motion opposing a stay.

III. Discussion

Petitioners make two arguments for reopening Docket No. RM79-54. First, they argue that the Commission erred in the final rule by allowing QF status for new dams. Petitioners contend that Congress intended in PURPA that only existing dams be granted QF status. Second, Petitioners argue that the Commission erred by not properly considering the environmental impacts of allowing QF status for new dams.

In addition to a programmatic EIS, Petitioners request an amendment to the regulations to foreclose qualifying status whenever the facility would adversely affect a waterway found by a Federal or state agency to have important natural, scenic, cultural, or recreational values. Alternatively, Petitioners ask that qualifying status be restricted to existing facilities.

A. QF Status for New Dams

PURPA was intended in part to encourage small power production. It did so by requiring the Commission to promulgate rules requiring electric utilities to purchase power from qualifying facilities at rates not exceeding the utilities' avoided costs of generating power. This preferential QF status was to be granted to, among others, certain small power production facilities that produce electric energy by means of "renewable resources."[12]

In 1979, the Commission issued a Notice of Proposed Rulemaking (NOPR)[13] to implement section 210 of PURPA. The NOPR proposed to restrict QF status for small hydroelectric facilities to existing dams. The NOPR relied on a House Conference Report[14] which stated that water is to be "included within the meaning of the term renewable resources with respect to hydroelectric facilities at existing dams."

Commenters on the NOPR urged the Commission to expand the definition of renewable resources to include water used at both existing and new hydroelectric facilities. In response to these comments, and on further review of the House Conference Report and the legislative history of PURPA, the Commission determined that notwithstanding the language in the Conference Report, Congress had not intended to restrict the meaning of the term "renewable resources" to water at existing dams. The Commission concluded that "such an interpretation conflicts with the conventional use of the term 'renewable resources' as including all hydroelectric resources, not just those using existing dams."[15] Therefore, in the final rule, the Commission promulgated regulations that allow QF status for both new and existing dams.

Petitioners had an opportunity to request rehearing of the final rule and failed to do so. They now contend, collaterally, that the Commission was incorrect in its interpretation of this phrase. However, Petitioners offer no new information or insight indicating that Congress intended to restrict the meaning of the term "renewable resources" to include water only at existing dams. The Commission therefore must reject Petitioners' request to reopen Docket No. RM79-54 on this ground.

B. Environmental Impact of New Hydroelectric Development

NEPA requires Federal agencies to prepare environmental impact statements whenever they undertake major Federal actions significantly affecting the quality of the human environment.[16] In the proceeding underlying the rules at issue here, the Commission's EA concluded that the PURPA incentives were not likely to encourage construction of new dams in the near term because the costs would outweigh the incentives, with the result that there would be no significant environmental effects during the near term. The EA also stated that the Commission would consider environmental concerns regarding hydroelectric QFs in hydroelectric licensing proceedings. Petitioners argue, again as a collateral challenge, that by not considering diversion projects, which generally are less expensive to build than dams, the Commission's conclusions concerning market penetration and consequent environmental impacts were faulty. In support of their theory, Petitioners cite various statistics concerning hydroelectric licensing activity since the regulations were promulgated, showing a marked increase in license applications for projects involving new dams and diversions. Petitioners assert that the increase in licensing and exemption proceedings demonstrates that the regulations authorizing eligibility of new structures for QF status represented a major Federal action significantly affecting the quality of the human environment and thus required an environmental impact statement (EIS).

Petitioners also contend that the Commission's practice of evaluating applications on a case-by-case basis does not result in adequate environmental review because the Commission seldom prepares an EIS and, when it does, it fails to consider the cumulative impact of PURPA-stimulated hydroelectric projects. Finally, Petitioners argue that the Commission has a continuing duty to gather and evaluate new information on the environmental impacts of its actions.[17] In this regard, they claim that the Commission, contrary to its statements in Order No. 70, has failed to monitor the market penetration of new hydroelectric facilities.

Petitioners have not made a persuasive case in favor of a programmatic assessment of the existing regulations at this time. Initially, the Commission notes that Petitioners' charge that the Commission fails to consider cumulative impacts in its hydroelectric licensing proceedings is incorrect. The Commission has established a Cluster Impact Assessment Procedure (CIAP) program for this very purpose. Under this program, the Commission, with assistance from Federal, state, and local agencies, considers the environmental impacts of proposed hydroelectric projects on a cumulative basis.[18]

Petitioners' allegation that the Commission has not monitored the market penetration of new hydroelectric QFs also is not correct. While the Commission had no formal market penetration study ongoing when the petition was filed, the Commission has since undertaken a comprehensive, nationwide survey of all QFs certified by the Commission or which have filed notices of self-qualification[19] since the establishment of the PURPA regulations. This study will give the Commission accurate and detailed information regarding the number of QFs planned, under construction and operating, their size and location, and other information useful in assessing environmental and other impacts of the QF program. This study, which is being conducted on the Commission's behalf by a contractor, is scheduled to be completed in the early autumn of this year.[20]

The Commission continues to adhere to the view that it can most effectively carry out its NEPA responsibilities in the context of hydroelectric licensing or exemption proceedings. A programmatic assessment of the existing QF rules would yield only general information. For instance, the Commission might assess scientific literature concerning the effects of reducing stream flow on fish spawning activity. This abstract information would, however, be of little assistance unless it is analyzed in relation to a specific project or projects. Only in the licensing procedures can the Commission reasonably determine whether a license should be granted or denied, and if granted, what specific mitigative measures are appropriate for that river or watershed. The same is true with respect to exemptions.[21]

Petitioners seek to bolster their request for a programmatic EIS by citing *American Public Transit Association v. Goldschmidt*, 485 F. Supp. 811 (D.D.C. 1980). There, the District Court held that regulations requiring Federally assisted public transport vehicles to be accessible to the handicapped constituted a major Federal action with nationwide effects, for which a programmatic EIS was required, notwithstanding that numerous individual EISs would be prepared for site-specific implementing programs. *Goldschmidt*, however, is readily distinguishable. That case involved a regulatory program mandating that specific actions be taken within specific time limits. The regulations embodied a decision which would inevitably result in the expenditure of billions of dollars and, as the agency acknowledged, have significant environmental impacts. Promulgation of those regulations, therefore, involved an "irretrievable commitment" of resources which would preclude alternatives. Hence, issuance of those regulations was itself a major Federal action with significant environmental impacts.[22]

The issuance of section 292.204, in Order No. 70, however, embodied no "irreversible commitment" of resources and did not (nor does it now) foreclose future options. As the Commission noted in the EA of March 1980, before any new hydroelectric facility can be constructed, and therefore affect the environment, the Commission must act affirmatively to issue a license or grant an exemption from licensing pursuant to Part I of the Federal Power Act.[23] If the Commission determines that a project would, even with mitigation measures, cause unacceptable adverse impacts on the environment, it will deny the license application.

Exemptions are handled somewhat differently, but with comparable results. Section 30(c) of the FPA gives the United States Fish and Wildlife Service and comparable state agencies the power to impose mandatory conditions on exemptions to protect fish and wildlife resources. These agencies are authorized to consider the individual and cumulative environmental impacts on these resources of issuing exemptions. Pursuant to their analyses, these agencies develop the mitigation measures to be included as mandatory conditions to the exemption. If these agencies determine that the environmental effects of a facility would, even with mitigation conditions, create unacceptable impacts, then this Commission will not grant the application for exemption.[24]

In contrast to the licensing and exemption processes, obtaining QF status does not authorize construction or operation of a facility, establish a site, or require the project developer to seek any licenses or take any other action. It also does not commit any Federal funds and does not determine the outcome of a hydroelectric licensing proceeding. The project developer, the Commission, and all other parties concerned have exactly the same options after certification as before.

Turning to Petitioners' specific alternative proposals, the Commission first notes that they are premised on Petitioners' arguments about the inadequacies of the current rule, which have been rejected above. Moreover, the Commission notes that it is responsible for balancing the aims of PURPA, NEPA, and the FPA. The purpose of Part I of the FPA is comprehensively to develop, conserve, and utilize water resources in the public interest.[25] The clear thrust of PURPA section 210(a) is to encourage small power production and cogeneration. NEPA is not intended to conflict with these purposes, but rather to ensure that the Commission, before taking any action in carrying out its responsibilities, weighs the environmental consequences of its actions and takes appropriate mitigative measures. As shown above, the Commission meets its responsibility to balance these statutory purposes by evaluating hydroelectric licensing and exemption applications on a case-by-case basis, with due regard for any cumulative impacts. Section 292.204 of the regulations does nothing to foreclose the Commission's ability to take the necessary balanced approach.

Petitioners' proposed alternatives, in the Commission's view, are not sufficiently flexible for the Commission to balance environmental considerations against other considerations. The first alternative, by foreclosing qualifying status whenever the facility would adversely impact a river segment found by a governmental agency to have important natural, scenic, cultural, or recreational values, is overbroad because it gives those values first priority over power production values in all cases.[26] Mitigation measures may well be sufficient to minimize or prevent adverse impacts on these competing values.

Petitioners' second proposed alternative, restricting qualifying status to existing facilities, is not appropriate for the same reason. A particular facility, as licensed, may not jeopardize the river segment's scenic, cultural, or recreational values. Yet, under the second alternative, no new facility built thereon would be eligible for QF status.[27]

In conclusion, the Commission finds that it can best carry out its responsibility to balance the objectives of PURPA, NEPA, and the FPA in the context of small hydroelectric projects by retaining the current regulations regarding eligibility of new facilities for QF status and continuing to assess the environmental impacts of such projects in the context of license and exemption applications, with due regard for cumulative impacts. The petition is, therefore, denied.

— Footnotes —

[1] "Petition for Amendment to 18 C.F.R. §§ 292.204 and 292.207 and for Preparation of an Environmental Impact Statement," filed on May 6, 1983, on behalf of The Naturel Resources Defense Council, The National Wildlife Federation, The Sierra Club, National Audubon Society, Western River Guides Association, The American Rivers Conservation Council, Friends of the Earth, Friends of the River Foundation, The Wilderness Society, California Trout, The Planning and Conservation League, The Natural Resources Council of Maine, Trout Unlimited, and the The American Wilderness Alliance (collectively, Petitioners).

[2] Small Power Production and Cogeneration Facilities—Qualifying Status, 45 Fed. Reg. 17,959

(March 20, 1980) (Order No. 70)(Docket No. RM79-54)(issued March 13, 1980) [*FERC Statutes and Regulations, Regulations Preambles 1977-1981* ¶ 30,134].

[3] 18 C.F.R. § § 292.204 and 292.207 (1985).

[4] 16 U.S.C. § § 796 and 824a-3 (1982).

[5] Those rules are found in 18 C.F.R. Part 292, Subpart B (1985).

[6] 16 U.S.C. § § 729-828c (1982).

[7] 15 U.S.C. § § 79-79z-6 (1982).

[8] Notice of No Significant Impact and Notice of Intent to Prepare Environmental Impact Statement, 45 Fed. Reg. 23,661 (April 8, 1980) (10 FERC ¶ 61,314) (March 31, 1980)).

[9] 42 U.S.C. § § 4321-4361 (1982).

[10] However, the Commission did determine that diesel and dual-fuel commercial cogeneration facilities in the Middle Atlantic region might have the potential to cause environmentally significant effects in the near-term. As a result, when the Commission issued its final rule in Order No. 70, it excluded new diesel cogeneration facilities from obtaining qualifying status, pending completion of a Final Environmental Impact Statement (FEIS). 45 Fed. Reg. at 17,965. The Commission issued the FEIS on May 1, 1981.

[11] *Sierra Club, et al. v. F.E.R.C.*, 9th Circuit No. 84-7720.

[12] Section 3(17)(A) of the FPA, as amended by section 201 of PURPA. 15 U.S.C. § 731 (1982).

[13] Proposed Regulations Providing for Qualification of Small Power Production and Cogeneration Facilities under Section 201 of the Public Utility Regulatory Policies Act of 1978, 44 Fed. Reg. 38,872 (July 3, 1979) (Proposed June 27, 1979) [*FERC Statutes and Regulations, Proposed Regulations 1977-1981* ¶ 32,028].

[14] H.R. Conf. Rep. No. 1750, 95th Cong., 2nd Sess. (1978).

[15] 45 Fed. Reg. at 17,966.

[16] 42 U.S.C. § 4332(2)(C) (1982).

[17] *Citing Warm Springs Task Force v. Gribble*, 621 F.2d 1024 (9th Cir. 1980).

[18] Procedures for Assessing Hydro Power Projects clustered in River Basins, 30 FERC ¶ 61,069 (1985); 31 FERC ¶ 61,095 (1985). The Commission also notes that the question of whether or not there are cumulative impacts was considered in licensing proceedings prior to the CIAP program. *See, e.g., City of Seattle, Washington*, 26 FERC ¶ 61,406, at p. 61,900 (1984); *Puget Sound Power & Light Company* and *Weyerhauser Company*, 26 FERC ¶ 61,405, at pp. 61,891-92 (1984). Such evaluations proceeded irrespective of the PURPA regulations, since QF status does not authorize the licensing, siting, construction, or operation of any facility. Each QF certification order reflects this fact.

[19] Commission certification of QF status is not required. The Commission's regulations provide that a facility is a QF if it meets the criteria set forth in the regulations. 18 C.F.R. § 292.207(a)(1) (1985). Commission certification is intended to provide certainty in cases where the project developer is in doubt as to whether the contemplated facility meets the criteria. If Commission certification is not sought, the Commission requires, for purposes of monitoring the market penetration of QFs, that the project developer file a notice of self-qualification. *See* 45 Fed. Reg. at 17,971.

[20] The Commission has also compiled a cumulative report on QF filings through December 31, 1984, which includes, *inter alia*, data identifying all certified hydroelectric QFs and their size. "The Qualifying Facilities Report," January 1, 1985.

[21] In this regard, the Commission notes that the fact that substantial numbers of hydroelectric QFs (including diversions) are being certified sooner than was supposed in the EA does not taint the EA's basic analysis. Whether a hydroelectric QF is developed in the near term or long term, its environmental impacts will still be evaluated in the licensing or exemption process.

[22] With respect to the timing of environmental review, it has been observed, in *Mobil Oil Corp. v. FTC*, 562 F.2d 170, 173 (2d Cir. 1977):

> (In determining when to prepare an EIS the agency must ascertain to what extent its decision embodies an "irretrievable commitment of resources" which precludes the exercise of future "options.") An EIS is required when the "critical agency decision" is made which results in irreversible and irretrievable commitments of resources to an action which will affect the environment.

[23] 45 Fed. Reg. at 28,683.

[24] *Olympus Energy Corporation*, 26 FERC ¶ 61,407 (1984). *See also Douglas Water Power Company*, 26 FERC ¶ 61,409 (1984).

[25] *F.P.C. v. Union Electric Co.*, 381 U.S. 90 at 101 (1964). ("[T]he comprehensive development of water power . . . was the central thrust of the [Federal Power] Act."); *City of Vanceburg, Ky. v. F.E.R.C.*, 517 F.2d 630, 632 (D.C. Cir. 1978) (One of the main purposes of the Federal Water Power Act of 1920, which became Part I of the Federal Power Act in 1935, is to encourage the development of hydroelectric power).

[26] At least insofar as hydroelectric facilities 80 MW and smaller are concerned. Facilities larger than 80 MW are not eligible for QF status in any event.

[27] Petitioners' proposal also is at odds with their assertion that NEPA mandates the attainment of "the widest beneficial use of river resources." Surely, the widest beneficial use will not be achieved by a policy that discourages, without any consideration of the specific circumstances, proposals to realize a waterway's power production values.

[¶ 61,009]

Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol (Eastern Shore Natural Gas Company), Docket No. RM85-1-000 (Parts A-D)

Order Granting Request for Clarification

(Issued January 9, 1986)

Before Commissioners: Raymond J. O'Connor, Chairman; A. G. Sousa, Charles G. Stalon, Charles A. Trabandt and C. M. Naeve.

On December 26, 1985, Eastern Shore Natural Gas Company filed a request for clarification that an interstate pipeline will not become subject to the conditions of Order No. 436 [1] by reason of transportation of emergency natural gas in accordance with Subpart C of Part 157 of the Commission's Regulations on behalf of another interstate pipeline.

Section 157.47(b) of the Commission's Rules specifically exempts interstate pipelines from the necessity of obtaining any other authorization under section 7 of the Natural Gas Act when they transport gas for another interstate pipeline in emergency situations, as "emergency" is defined in section 157.46. This exemption constitutes a grant of authority independent of the transportation authorized by Order No. 436. Thus, Order No. 436 is inapplicable to emergency transportation performed by an interstate pipeline for another interstate pipeline pursuant to Subpart C of Part 157, and does not subject the interstate pipeline to the conditions in the regulations adopted by Order No. 436.

— Footnote —

[1] 50 Fed. Reg. 42,408 (October 18, 1985) [*FERC Statutes and Regulations* ¶ 30,665].

[¶ 61,010]

Colorado Interstate Gas Company v. MIGC, Inc., Docket No. GP85-20-002

Order Granting Rehearing Solely for the Purpose of Further Consideration, and Granting in Part Request for Stay

(Issued January 9, 1986)

Before Commissioners: Raymond J. O'Connor, Chairman; A. G. Sousa, Charles G. Stalon, Charles A. Trabandt and C. M. Naeve.

Request For Rehearing

On November 13, 1985, the Commission issued an "Order Disallowing Notice of Withdrawal and Denying Appeal From Order of the Production-Related Costs Board" in the above docket. 33 FERC ¶ 61,200. On December 13, 1985, MIGC, Inc. (MIGC) and MGPC, Inc. (MGPC) filed a timely "Request for Rehearing and for Stay" of that order. In order to afford additional time for consideration of the issues raised in the request for rehearing, the Commission will grant rehearing of its order of November 13, 1985, solely for the purpose of further consideration. As provided in Rule 713(d) [1] of the Commission's Rules of Practice and Procedure, no answers to the request for rehearing will be entertained by the Commission.

Request for Stay

MIGC and MGPC state that the September 24, 1985, Offer of Settlement in Docket Nos. RP84-15-000, *et al.*, would resolve the matters in Docket No. GP85-20-001, and ask for a stay of the effectiveness of the November 13 order issued in that docket, pending Commission consideration of the Offer of Settlement in Docket Nos. RP84-15-000, *et al.*, and until 30 days after the Commission issues an order on the merits of the rehearing request in Docket No. GP85-20-002.

Ordering Paragraph (C) of the November 13 order requires MGPC to account for and refund excess collections as provided in the September 13, 1985 order of the Production-Related Costs Board which MIGC and MGPC had jointly appealed. 32 FERC ¶ 62,574. Since the date for refunds (January 12, 1986) will arrive before the Commission issues an order on the merits of the request for rehearing, good cause exists to grant MIGC and MGPC's request for stay of the effectiveness of the November 13 order, with respect to the disbursement of refunds, until 30 days after the Commission issues an order on the merits of the rehearing request in this docket.

Accordingly, a stay of Ordering Paragraph (C) will be granted in part, as regards refund disbursement. However, no stay will be granted as regards the *calculations* required to be made. These calculations shall be submitted to the Commission's audit staff as required by paragraph (C). This data will enable the Commission to evaluate fully the parties' claim that the Settlement Offer in Docket No. RP84-15-000, *et al.*, resolves the complaint and violations found in the Board's order of September 13, 1985.

The Commission orders:

(A) The Commission grants rehearing of its order of November 13, 1985, solely for the purpose of further consideration.

(B) The Commission grants a partial stay of its order of November 13, 1985, solely with respect to the requirement that any refund monies be disbursed; this partial stay to be effective until 30 days after the Commission issues an order on the merits of the rehearing request.

(C) The calculations required to be made shall be submitted to the Commission's audit staff pursuant to Ordering Paragraph (C) of the November 13, 1985, order.

— Footnote —

[1] 18 C.F.R. § 385.713(d) (1985).

[¶ 61,011]

Consolidated Edison Company of New York, Inc.; Docket Nos. ER85-763-002 and ER85-598-005, et al.

Notice of Denial of Rehearing

(Issued January 9, 1986)

Kenneth F. Plumb, Secretary.

On December 11, 1985, the Municipal Electric Utilities Association of New York State filed a request for rehearing of the Commission's order issued in this proceeding on November 12, 1985, 33 FERC ¶ 61,194. The Commission has determined to take no action on the request for rehearing. Therefore, rehearing should be deemed denied 30 days after filing pursuant to Rule 713 of the Commission's Rules of Practice and Procedure. 18 C.F.R. § 385.713.

[¶ 61,012]

Town of Skykomish, Washington, Project No. 6537-002

Notice of Denial of Rehearing

(Issued January 9, 1986)

Kenneth F. Plumb, Secretary.

Take notice that the Commission agreed to take no action on the request for rehearing of its November 12, 1985 order denying appeal in the above-captioned proceeding (33 FERC ¶ 61,192 (1985)), filed by the Tulalip Tribes of Washington on December 10, 1985. Accordingly, the request for rehearing is denied pursuant to Section 313(a) of the Federal Power Act, 16 U.S.C. § 825*l*(a) (1982), and Rule 713(f) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(f) (1985).

[¶ 61,013]

South Central Terminal Company, Inc., Docket No. RO85-13-000

Order on Remand

(Issued January 10, 1986)

Before Commissioners: Raymond J. O'Connor, Chairman; A. G. Sousa, Charles G. Stalon, Charles A. Trabandt and C. M. Naeve.

On December 20, 1985, the Presiding Administrative Law Judge, not knowing that a request for oral argument filed pursuant to Rule 909 of the Commission's Rules of Practice and Procedure was pending, certified to the Commission the record in this proceeding together with a draft order. When the Presiding Administrative Law Judge discovered the existence of the request for oral argument, which had been misfiled through office error, oral argument was scheduled to be held on January 9, 1986. The Presiding Administrative Law Judge also informally made a request to the Secretary of the Commission to withdraw the certification and draft order. At that time the draft order had not reached the Commission, and it was returned to the Presiding Administrative Law Judge.

South Central Terminal Company, Inc. on January 3, 1986, filed motions to stay the oral hearing, remand the case, and to designate a new and different Presiding Officer. South Central Terminal Company, Inc. also requested that the "proposed order" be invalidated.

The Chief Administrative Law Judge, by order issued on January 7, 1986 [32 FERC ¶ 63,003], stayed all hearing procedures in this proceeding pending action by the Commission on the petitions for remand.

The Commission finds that good cause has been shown to remand this case to the Presiding Administrative Law Judge to conduct the requested oral argument, and to certify the record, including the transcript of the oral argument, to the Commission. The Presiding Administrative Law Judge will also prepare a draft order for the Commission based upon the complete record in this proceeding including the oral argument. Further, the Commission finds South Central Terminal Company, Inc.'s motion to designate a new Presiding Officer in this proceeding to be without merit, and it is denied.

The Commission orders:

This proceeding is remanded to the Presiding Administrative Law Judge to conduct oral argument. Following the oral argument, the Presiding Administrative Law Judge will certify the record in this proceeding to the Commission together with a draft order.

The motion of South Central Terminal Company, Inc. to designate a new Presiding Officer in this proceeding is denied.

ADDRESS ALL COMMUNICATIONS
TO THE COMMISSION

CALIFORNIA STATE BUILDING
SAN FRANCISCO, CA 94102
TELEPHONE (415) 557-1341

Public Utilities Commission
STATE OF CALIFORNIA

July 1, 1986

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
[illegible] 1986
WASHINGTON D.C. 20510

Senator James McClure
United States Senate
Committee on Energy and Natural
Resources
Washington, D.C. 20510

Dear Senator McClure:

Enclosed are answers to the follow-up questions that you asked me regarding PURPA. We would be happy to provide any further information that you desire.

Thank you again for inviting me to testify at your hearing. I hope it contributes to your understanding of this complex program.

Sincerely,

Duncan Wyse

Duncan Wyse, Director
Policy and Planning Division

Enclosures

Responses to Questions on PURPA from Senator Dale Bumpers:

1. How much has cogeneration and small power production contributed to the electricity supply in your jurisdiction in the past year? What is your best guess as to the contributions from these sources over the next three years? Five years? Ten years? Fifteen years?

> As of December 1985, the three major California utilities had 2,873 mW of cogeneration and independent power production on line, equal to about 10% of the peak demand for that month; by March 31, 1986, there were 3,034 mW of independent and cogeneration production on line.
>
> In August of 1985, the electricity received from independent producers on PG&E's system equaled about 6% of their total energy demand; in August of 1982, this percentage was about 1%.
>
> Trying to estimate the contribution from these sources in the future is very uncertain. In California, there are almost 13,000 mW of independent and cogeneration power with signed commitments to produce power which are not yet on-line. Not all of these sources will materialize. Most experts estimate that between 40% and 60% of these source will come on-line within the next five years. This would result in a program of between 8,000 and 10,000 mW by 1990.

2. Are you generally satisfied that PURPA has benefitted ratepayers in your jurisdiction? What evidence would you cite supporting your conclusion?

> Implementation of PURPA has contributed tremendous benefits to the ratepayers of California. Without the over 3,000 mW currently on-line, California's ratepayers would be saddled with paying for generation from expensive oil and gas facilities at the margin. In addition, supplies to meet future load growth would have to be constructed by utilities, a prospect which is unnecessary in the near future due to the growth in current and expected independent power supplies.

3. Has the availability of electricity from cogeneration and small power production contributed significantly to deferral of any central station plants in your jurisdiction? Is this likely in the future?

> California utilities had a number of coal and nuclear projects on the drawing boards in the 1970's for meeting projections of need. A number of circumstances have occurred to alleviate the need for such construction over the last few years, namely reduced demand and increased independent

generation. Attempting to determine which of these results deferred which plants is, of course, difficult. However, given actual demand growth and QF power growth, at least two large coal plants can be said to have been deferred, in part, due to the growth in QF supplies:

- The Harry Allen Warner project, four 500 mW coal units which were scheduled to come on-line in the mid-1980's in a joint project by Southern California Edison and Pacific Gas & Electric;

- The Montezuma project, two 800 mW coal units proposed by PG&E to come on-line in the mid- to late-1980's.

It is highly likely that the independent power program in California will continue to defer and avoid the need for large baseload construction. With the number of signed contracts expected to actually come on-line, and a new long-run standard offer expected to be available by early next year, California's QF program will continue to provide the benefits of deferred construction for many years. In fact, the new long-run offer will have prices based on utility proposed plants which are deferred by QF power. Thus, QFs will receive directly the benefits of the construction they contribute to avoiding.

4. How do you balance the need to encourage cogeneration and the interests of the ratepayer?

The pricing policy established by the Federal Energy Regulatory Commission under PURPA used "avoided cost pricing" as the guideline for the value of power from cogenerators and small power producers. Under avoided cost principles, prices for independent producers equal the costs avoided by a utility by purchasing from the producers. With such a framework, ratepayers are initially indifferent, in price terms, between power produced by the utility and power produced by an independent generator.

However, over time ratepayers do benefit as the efficiency of the electric system improves with increased independent producers supply electricity to the system. As these supplies increase, utilities are able to turn off their least efficient plants as well as avoiding the construction of new plants. As a result, system efficiencies increase, avoided cost prices fall further, and ratepayers pay less for the electricity they use. Ratepayers also benefit from a variety of other attributes of independent power, including the diversity of the resource mix, enhanced system reliability, and reduced risk from traditional ratemaking. Avoided cost pricing also maximizes the benefit to the independent producer while encouraging efficient production.

5. Have the utilities in your jurisdiction cooperated in the implementation of PURPA? Please discuss the utility response.

While California utilities are now among the country's leaders in developing QF generation sources, early in the development of the program this was not the case. Before the CPUC had fully developed the implementation of standard offers and their associated methodologies, utilities were left to negotiate contracts with interested parties on a case-by-case basis.

Through some investigations, the CPUC staff found several instances of unfair dealings by both Pacific Gas and Electric and Southern California Edison. PG&E was fined $7 million for unfair dealings in 1979; by the end of 1980 the company had corrected the problems and was implementing the CPUC mandates satisfactorily. Edison was fined $10 million a year later for not signing contracts at prices greater than 85% of full avoided costs. Since then, the utilities have become much more encouraging toward independent generation.

6. Are you concerned that PURPA may result in the loss of industrial load by any of your utilities? If so, what do you propose to do about it?

The loss of industrial load, or by-pass, is a function of much more than the requirements of PURPA. By-pass is primarily an industrial rate design issue, not a PURPA issue.

By-pass occurs when it costs a customer more to purchase electricity from a utility then to produce it independently. It is particularly inefficient when a utility can actually produce the electricity at a lower marginal cost then the customer. Many utilities find themselves in this situation, with rates well above marginal costs, because they need to recover the costs of large fixed investments; this is especially the case for utilities with nuclear plants coming on-line soon.

If it were possible to set rates equal to the marginal costs of production, by-pass would not be as serious a problem. However, given the fact that large fixed costs must be recovered, rates must be greater than marginal costs. At the California PUC, we are currently studying this issue in our rate design proceedings.

7. On June 3 we heard testimony that suggests there are significant safety and reliability problems with PURPA. Are you aware of any such problems? If so, please describe them and tell us what you are doing to mitigate these problems.

California has not had safety or reliability problems with its independent power producers. In fact, given the number of producers in California, we have an exemplary safety record.

Response to natural gas questions of Senator J. Bennett Johnston

This set of questions is best addressed through an explanation of current efforts to modify natural gas policy in California:

> California is currently examining and implementing a number of changes in regard to natural gas policy. Natural gas fired cogeneration, as a subset of industrial natural gas consumption, will have two options for natural gas supply under the proposed rules. The first option involves remaining with the utility gas supply system; this means allowing the utility to contract for gas from suppliers and transport the gas to the user. While this would look much like the traditional natural gas supply arrangement, these cogenerators would be given the option, like other industrial gas users on the utility system, to contract specifically for the utility to obtain supplies with higher reliability.
>
> A second option is for the cogenerator to contract with the natural gas producer directly for the purchase of natural gas, and pay interstate pipelines and the utility to transport the gas to the cogeneration site. Under this option, the cogenerator is given the responsibility for assessing their own reliability needs and contracting with the producers, pipelines and distributors accordingly.
>
> Assessing the impact of potential natural gas shortages on cogeneration capacity is difficult. Because these rules have not yet been implemented, and will not go into place until January 1, 1987, at the earliest, we do not yet know what degrees of certainty cogenerators remaining with the system will choose, nor do we know how much certainty cogenerators choosing the transport option will contract for with producers and transporters. It is important to stress that under proposed gas policy at the CPUC cogenerators themselves will explicitly make the decision of how much to pay for supply certainty.
>
> California does not require a backup fuel capacity for its natural gas-fired cogenerators. Cogenerators are at risk, like other industrial natural gas users, from supply uncertainties. Cogenerators have the option, as mentioned earlier, to contract for more reliable supplies with the utility or directly with producers.
>
> However, in a more deregulated market, cogenerators in California will probably find it economical to maintain electricity production for the system in the face of supply shortages. Utilities burn natural gas in their boilers; consequently, in the case of a shortage, natural gas prices will rise for both utilities and cogenerators; while this means that cogenerator costs of production will increase, and the cost of maintaining secure supplies will increase, it also means that the avoided-costs they receive for their power production will increase as well (because the marginal fuel for California utility production is predominantly natural gas).

Responses to PURPA questions from Senator J. Bennett Johnston

1. Given the fact that oil and natural gas are ultimately scarce resources, wouldn't national energy policy be better served by requiring the electrical capacity of an oil or gas-fired cogeneration facility to be a function of the thermal need to be served?

> If prices to QFs are equal to the avoided costs of the utility, ratepayers are indifferent to whether the utility or QF provides the electricity. If the avoided fuel of the utility is natural gas or oil, as it currently is for most California utilities, a gas or oil-fired cogenerator will only find it profitable to provide power if their operation is more efficient at burning fuel then the utility is.

2. Is there any justification for requiring utilities to buy capacity from qualifying facilities that the utilities do not need within their existing planning horizons? Doesn't this represent a net cost to consumers?

> The issue of requiring utilities to buy capacity from qualifying facilities that the utilities do not need can be addressed through considering what a QF is really providing a utility. In essence, there are two products provided by QFs as a joint output of the operation of their facility.
>
> The first output is energy, measured in kWh. A QF operating at a level of 100 kW for one hour provides 100 kWh to the utility. Energy almost always has a value to a utility; if a utility can provide 100 kWh at a cost of $2.00 (for fuel, labor, etc.) then it would be willing to pay a QF that much to provide 100 kWh and avoid its own operation. This "avoided energy cost" depends on the efficiency of the utility plant providing power at the margin, the fuel to operate that plant, and a variety of other operational inputs.
>
> The second output a QF provides is capacity. This is measured in kW, and reflects the potential amount of power a facility can provide during periods of shortages. Capacity also almost always has a value in terms of the reliability it provides the system. This reliability is more valuable when a utility's reserve margins are low, i.e., when it risks not having enough capacity to meet demand. But even if a utility's reserve margins are relatively high, a QF's capacity can contribute some amount of increased reliability to the system and, thus, the QF should be paid for that contribution.

3. What justification is there for retaining a 100 percent avoided cost standard? In those areas where there has been extensive development of qualifying facilities, couldn't there be a provision for the payment of less-than full avoided cost rates without discouraging further development?

Continuing the payment of full avoided costs to QFs continues to encourage the development of such facilities as an alternative to utility construction. While paying full avoided costs does not appear to give any benefits to ratepayers, ratepayers are actually benefiting from a variety of other QF attributes which cannot be valued. For one, QFs provide a diversity of resources for a generation system which insulate ratepayers from price shocks which occur when a system depends on one type of fuel source. For example, in the early 1970's ratepayers found themselves suffering rate increases because utility systems were too dependent on volatile oil and gas costs.

QFs also insulate ratepayers from the outage risks which occur from utility system's dependence on large baseload plants. If a large coal plant has to shutdown, some ratepayers may face lengthy outages. The odds of enough QFs shutting down to equal a large utility resource are very slim.

Ratepayers also avoid the risks which occur from the construction of large baseload plants. The recent history of cost escalations for constructing nuclear and coal plants shows the potential cost risks ratepayers face if construction costs increase before a plant can even produce any electricity.

Ratepayers gain additional efficiency benefits over time as QF participation grows. As supplies from QFs increase, utilities are able to turn off their least efficient plants as well as avoid constructing new plants. As a result, avoided costs fall, resulting in even lower costs for QF energy.

Finally, QFs benefit the ratepayers by shifting the risk of plant performance away from the ratepayers and onto the plant operators. With a utility system, if a plant must be shutdown, for safety or operational reasons, ratepayers continue to pay the capital and O&M costs for the plant, even though it may never produce any more electricity. With QFs, on the other hand, ratepayers only pay for the energy and capacity a QF actually provides, and if the QF shuts down for any reason, ratepayers bear none of the risk.

For these reasons, ratepayers continue to receive benefits for QF power, even though, on an apparent cost basis, full avoided cost payments make it appear as if they are indifferent and receive no benefits.

IDAHO PUBLIC UTILITIES COMMISSION

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PERRY SWISHER, *President*
CONLEY WARD, JR., *Commissioner*
RICHARD S. HIGH, *Commissioner*

JOHN V. EVANS
Governor

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SENATE COMMITTEE ON
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June 27, 1986

The Honorable James A. McClure, Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

JUL 02 1986

Dear Senator McClure:

Commissioner Swisher is unable to respond to the Senate Committee's request personally due to his illness. In Commissioner Swisher's absence, the Staff of the Idaho Commission is offering the following answers in response to the questions of Senators Bumpers and Johnston. We hope the Staff's response is helpful.

If you have any questions, please do not hesitate to contact us.

Yours truly,

Don C. Reading, Director
Policy & Administrative Services

DCR:sh/59Q
Enclosure

Questions on PURPA from Senator Dale Bumpers

1. How much has cogeneration and small power production contributed to the electricity supply in your jurisdiction in the past year? What is your best guess as to the contributions from these sources of electricity over the next three years? five years? ten years? fifteen years?

   A. Cogeneration and small power production has contributed to the electricity supply 125.5 MW in the past year (1985) within the state of Idaho. There is no formal forecast as to the future growth in CSPP; even so, there will be little growth in the near term due to the recent reduction in the avoided cost rates.

2. Are you generally satisfied that PURPA has benefitted ratepayers in your jurisdiction? What evidence would you cite supporting your conclusion?

   A. If PURPA is working, and I believe there is ample evidence to prove this, then the ratepayers are benefitting. The underlying intent of PURPA is to encourage the use of energy-efficient technologies, such as cogeneration and non-utility power, produced from renewable resources. The enactment of PURPA removed many barriers to the growth of industrial cogeneration by freeing industrial cogenerators from utility-type regulations, assuring interconnection to the utility grid, requiring utilities to purchase power at a fair and reasonable price and assuring that utilities provide standby power at a fair price. All of these factors have encouraged the production of new electric generation, even though it is not presently needed, it is expected that the long-run costs will be less than other alternatives. But the jury is still out as to ratepayer benefit. Only time will tell if the QFs will continue to produce dispatchable, reliable power through the contract period when additional power is needed, and only then will the ratepayers realize a benefit.

3. Has the availability of electricity from cogeneration and small power production contributed significantly to deferral of any central station plants in your jurisdiction? Is this likely in the future?

A. It is still too early to pinpoint reasons for deferral of any central station plant. We in the Northwest are in a surplus mode and would not be building central plants at this time. However, the influence of QF power being supplied has caused a re-evaluation of our utilities' resource and planning for the near term . In most cases, new plant planning has been either shelved or pushed back two to three years into the future.

4. How do you balance the need to encourage cogeneration and the interests of ratepayers?

A. The need to encourage cogeneration is not a primary factor at the present time. Cogeneration has come of age and is recognized as a proven technology, providing energy efficient by-products marketable in the market place.

5. Have the utilities under your jurisdiction cooperated in implementation of PURPA? Please discuss the utility response.

A. This is a difficult question to answer. We must remember the utilities have been king of the hill in the electric power business and PURPA comes along and rewrites the rules. The concern about capacity, diversity, quality, reliability, safety, and prudent decisions regarding the ratepayers are justifiable concerns by the utility which, in many cases, are misunderstood by the QF as not negotiating in good faith. This is not to excuse the foot dragging and stalling by some of the utilities which has taken place. The utility has responded to PURPA as a necessary evil and if we ignore it, it will go away. However, in the meantime, we will live with it. Many pitfalls by the QF have been avoided because of the utilities in-depth concerns for the long term. I refer to the reserve funds, sinking accounts, security, insurance, liquidated damages and other precautionary pay backs which may have to be employed.

6. Are you concerned that PURPA may result in loss of industrial load by any of your utilities? If so, what do you propose to do about it?

A. The underlying intent of PURPA is to encourage the use of energy-efficient technology such as cogeneration and it is natural to believe that the industrial load will be reduced proportionately. However, any loss of industrial load could be used in their resource planning to extend the need for new plant by months or years into the future. We must keep in mind, an interruptible back-up load for the replaced industrial load is part of PURPA and must be provided by the utility.

7. On June 3 we heard testimony that suggests there are significant safety and reliability problems with PURPA. Are you aware of any such problems? If so, please describe them and tell us what you are doing to mitigate these problems?

A. No comment.

Questions for State Regulators from Senator J. Bennett Johnston

In response to all questions regarding natural gas fired cogeneration facilities:

> In the state of Idaho we are steeped in hydro and thermal generation for cogeneration and small power production. Natural gas has not presently been utilized in our cogeneration facilities. As a regulator, we naturally would be concerned if large amounts of electrical generation were dependent on natural gas for fuel.

PURPA OVERSIGHT HEARING QUESTIONS SUBMITTED FOR THE RECORD FROM SENATOR J. BENNETT JOHNSTON

1. The Committee heard significant testimony concerning so-called "PURPA machines" -- oil or natural gas fired cogeneration facilities that satisfy FERC's efficiency standards but that produce more electricity and burn more fuel with less efficiency than would be the case if the facilities were sized to meet their thermal needs. Given the fact that oil and natural gas are ultimately scarce resources, wouldn't national energy policy be better served by requiring the electrical capacity of an oil or gas-fired qualifying cogeneration facility to be a function of the thermal need to be served?

   A. The underlying intent of PURPA to encourage the use of energy-efficient technologies such as cogeneration must be properly balanced between thermal needs and production of electricity if you are to realize the benefits of energy efficiency through the use of reject heat. This energy efficiency must be monitored by FERC at the time of approval to eliminate the "PURPA machine" concept.

2. Is there any justification for requiring utilities to buy capacity from qualifying facilities that the utilities do not need within their existing planning horizons? Doesn't this represent a net cost to consumers?

   A. Capacity payments to QF in times of surplus power have been a major issue in recent hearings. Capacity payments can only be justified when new capacity is being added by the utility within their planning horizon.

3. What justification is there for retaining a 100 percent full avoided cost standard? If there was, for example, an 80 percent avoided cost standard, electric consumers would directly receive the savings, namely, the 20 percent difference between the utility's avoided cost and what it would be required to pay a qualifying facility. Originally, FERC considered a less-than-full avoided cost standard but rejected it because little development of qualifying facilities was expected;, and encouragement of a diversified power supply was thought to be more important. However, the growth of cogeneration and small power production has exceeded original expectations. In those areas where there has been extensive development of qualifying facilities, couldn't there be a provision for the payment of less-than-full avoided cost rates without discouraging further development?

   A. Yes, I believe this phenomenon is now taking place in some areas of the country. There are bidding processes taking place which reflect a less-than-full avoided cost, as viewed from the market place without discouraging further development.

SENATE COMMITTEE ON
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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION
ALBANY 12223

PAUL L. GIOIA
CHAIRMAN

THREE EMPIRE STATE PLAZA

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July 17, 1986

Dear Senator McClure:

Enclosed are responses to the follow-up questions on PURPA set forth in your letter of June 13, 1986. If we can provide any further information, please let me know.

Sincerely,

Paul L. Gioia

Enc.

Hon. James A. McClure
Chairman, United States Senate
Committee on Energy and Natural Resources
Washington, DC 20510

STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

Questions From Senator Bumpers

1. How much has cogeneration and small power production contributed to the electricity supply in your jurisdiction in the past year? What is your best guess as to the contributions from these sources of electricity over the next three years? five years? ten years? fifteen years?

The Commission has received 266 contracts with cogenerators and small power producers for a total capacity of 537 MW. Of this amount approximately half or 250 MW was actually in service and supplying electricity in 1985. Forecasts of the amount of such generation over the next 15 years have been prepared by the State Energy Office. Attached are copies of the relevant pages from the Energy Office's December 1985 report showing cumulative additions between 1468 MW and 3319 MW by the year 2001 depending upon the level of price incentives. We believe the lower end of this range would be the most realistic.

2. Are you generally satisfied that PURPA has benefitted ratepayers in your jurisdiction? What evidence would you cite supporting your conclusion?

Yes, PURPA has benefitted ratepayers in several ways: First, certain large industrial ratepayers have been able to lower their costs and remain economically viable because PURPA allowed them to build cogeneration and interconnect with the utility system. Not only did this benefit certain industrial consumers, such actions also benefitted the general body of ratepayers. For example, in industry executives faced with deteriorating economics may decide to leave the state resulting in the remaining ratepayers having to pick up the contribution to common costs formally paid by the industry.

Second, PURPA has encouraged the building of certain facilities which take advantage of the states' indigenous resources. For example, in New York State, developers have built or rebuilt nearly 90 hydroelectric projects. These projects are very long-life facilities and result in continuing reductions in the amount of fossil fuel consumed in this State. Development of these resources is in the long-term best interest of ratepayers.

Third, the problem of the disposal of municipal wastes is a concern of ratepayers in their dual role as taxpayers. Landfills are becoming scarce and it seems wasteful to simply incinerate wastes without utilizing the resultant energy. Hence, the development of refuse power plants is a benefit to ratepayers, taxpayers, and the State as a whole.

3. Has the availability of electricity from cogeneration and small power production contributed significantly to deferral of any central station plants in your jurisdiction? Is this likely in the future?

No. The only power plants cancelled or postponed in New York State were due to declining loads or environmental objections. Since the early 1980's, utilities have claimed that no major additions are required before the year 2000. In any event, the "deferral of any central station plants" may not be the least cost strategy for this State. Recently, the Commission has ordered a new proceeding to determine the least cost method of meeting future state energy needs. These methods, all of which may be a part of a total strategy, include cogeneration utility-built plants, conservation and load management.

4. How do you balance the need to encourage cogeneration and the interests of ratepayers?

This balance is best accomplished by setting the purchase price for cogeneration at a reasonable forecast of avoided costs. The "interests of ratepayers" should be a least cost reliable electric supply in the future. The utilities currently have that statutory obligation; cogenerators do not. Nonetheless, if cogenerators can contribute to a least cost strategy they should be encouraged to do so up to the level of what it would otherwise cost the utilities to produce the same amount of power.

5. Have the utilities under your jurisdiction cooperated in implementation of PURPA? Please discuss the utility response.

The reaction to PURPA has been mixed. All utilities have been willing to contract with cogenerators and small power producers at full avoided costs as defined by tariffed numbers developed in each rate case. Some utilities have been reluctant to sign long-term fixed priced contracts since there's a risk the utilities would overpay for this electricity should avoided costs turn out to be lower than expected.

In March 1986, the Commission issued an order in Case 28962 establishing a 15-year forecast of avoided costs and requiring utilities to enter into contracts based upon such numbers. Except for a request by one utility to have these numbers updated more frequently than annually, the utilities have not opposed this directive.

6. Are you concerned that PURPA may result in loss of industrial load by any of your utilities? If so, what do you propose to do about it?

PURPA may result in the loss of industrial load especially in those areas where retail electric rates are higher than avoided costs e.g., Con Edison. To date, there have been insignificant amounts of such losses. In some cases, the building of such facilities may help encourage an industry to remain in New York State. The loss of an industrial facility may have much more damaging effects than the potential loss of electric load through self-cogeneration.

7. On June 3 we heard testimony that suggests there are significant safety and reliability problems with PURPA. Are you aware of any such problems? If so, please describe them and tell us what you are doing to mitigate these problems.

New York has not experienced any safety or any reliability problems with PURPA. We have very carefully established our procedures and guidelines to avoid such problems. Because of excess capacity in New York, very little is included in buy-back rates for capacity payments. Hence, reliability is not a immediate concern.

However, the Commission recently granted a petition by a developer for fixed payments for 15 years that are likely to exceed avoided costs with steep discounts from actual avoided costs in later years. In that case, the Commission required the developer to offer performance guarantees in return for the fixed payment contract.

We suggest, however, that states consider a competitive bidding process where developers could compete to build large cogeneration equipment at a certain percentage less than full avoided costs. This offers advantages to the ratepayer and also addresses the problem of encouraging on-site generations.

Questions From Senator Johnston

1. The Committee heard significant testimony concerning so-called "PURPA machines" -- oil or natural gas-fired cogeneration facilities that satisfy FERC's efficiency standards but that produce more electricity and burn more fuel with less efficiency than would be the case if the facilities were sized to meet their thermal needs. Given the fact that oil and natural gas are ultimately scarce resources, wouldn't national energy policy be better served by requiring the electrical capacity of an oil or gas-fired qualifying cogeneration facility to be a function of the thermal need to be served?

We would agree that such a policy makes sense. In our experience, however, we find that the economics of such projects are poor unless the energy output (and the revenues derived from electric sales) is increased significantly. Mandating a strict thermal balance for cogeneration facilities may serve to eliminate a number of such installations. As long as the price to be paid for such power is reasonably based on the utilities full avoided cost and proper consideration is given to fuel availability, a thermal balance requirement is not necessary.

2. Is there any justification for requiring utilities to buy capacity from qualifying facilities that the utilities do not need within their existing planning horizons? Doesn't this represent a net cost to consumers?

Yes, there is justification. From a standpoint of economics there is always value to additional capacity in the form of greater reliability. For example, although there is currently a 40 percent reserve margin in New York and no plans within the next 15 years for utility-built central generation equipment, additional capacity does, in fact, have value, albeit small. As long as this value is properly calculated, there should be no "net costs" to ratepayers.

3. What justification is there for retaining a 100 percent full avoided cost standard? If there was, for example, an 80 percent avoided cost standard, electric consumers would directly receive the savings, namely, the 20 percent difference between the utility's avoided cost and what it would be required to pay a qualifying facility. Originally, FERC considered a less-than-full avoided cost standard but rejected it because little development of qualifying facilities was expected, and encouragement of a diversified power supply was thought to be more important. However, the growth of cogeneration and small power production has exceeded original expectations. In those areas where there has been extensive development of qualifying facilities, couldn't there be a provision for the payment of less-than-full avoided cost rates without discouraging further development?

The use of a 100 percent full avoided cost standard should remain. This standard applies to mostly nontraditional sources of power e.g., hydro, wind, cogeneration. Hence, if developers are paid full avoided costs not only are the ratepayers indifferent, but ratepayers will enjoy more diversified and perhaps more efficient sources of power. This has unquantified long-term benefits and perhaps environmental advantages.

Further Questions from Senator Johnston

1. As a regulator charged with protecting the public interest, are you at all concerned with natural gas supplies for these facilities?

Yes. We recently rejected a petition by a developer who wanted to build a natural gas cogeneration faciltiy and needed a fixed price long-term contract where the first several years had payments above avoided cost. Part of the reason for such rejection was the concern over the gas supply. The Commission was concerned about fuel availability at a time when the amount of front loaded money advanced to the developer was significant.

For facilities that supply energy only and are paid short-term tariff buyback rates, we have no concern over fuel supplies at this time.

2. What would happen to the cogeneration capacity the utility is depending on in the event of a natural gas curtailment?

New York State currently does not have enough natural cogeneration to be concerned. We would expect, however, that this would be a part of the Commission's recently instituted long-range least cost strategy planning case.

3. Are the gas supplies for the cogeneration facilities generally from a pipeline's system supply, and thus afforded a low priority in the event of curtailment, or do they have their own supplies that are simply being transported by the pipelines?

Generally, gas supplies for cogeneration purposes are received from interstate pipeline companies through a utility distribution system. All large cogenerators in New York are required to maintain dual fuel capability and are thus classified as interruptible customers with an appropriate curtailment priority of six (ref. Opinion No. 77-2, 3/11/77).

4. Does your state require any backup fuel capacity, or are the cogenerators solely dependent upon natural gas for fuel?

Small cogenerators (less than 12,000 Mcf/yr) are considered firm customers and are afforded a curtailment priority of ten. There are 15 curtailment priorities with residential customers enjoying the top priority of fifteen.

APPENDIX III

Additional Material Submitted for the Record

CITY OF PHILADELPHIA

W. WILSON GOODE
MAYOR

June 2, 1986

The Honorable James A. McClure
United States Senator
Dirksen Building, Room 358
Washington, D. C. 20510

Dear Chairman McClure:

I was interested to hear that the Senate Committee on Energy and Natural Resources is having preliminary hearings on small power production and cogeneration. The City of Philadelphia is one of many municipalities across this nation which plans to use trash-to-energy technology as an integral part of its waste management system. As such, it is critical that utilities continue to be required to purchase the electricity produced by these facilities at full avoided costs.

I look forward to testifying before your Committee in the future on this issue. For now, I have enclosed a copy of a statement that I have filed with the Committee. This statement has been endorsed by the United States Conference of Mayors and the National Resource Recovery Association. If you have any questions, please do not hesitate to contact me.

Sincerely,

W. WILSON GOODE

DMB:gg

STATEMENT

TO THE

SENATE OF THE UNITED STATES
COMMITTEE ON ENERGY AND NATURAL RESOURCES

REGARDING

PRIVATE POWER PRODUCTION AND WASTE MANAGEMENT

PRESENTED BY

W. WILSON GOODE, MAYOR OF PHILADELPHIA

UNITED STATES CONFERENCE OF MAYORS

NATIONAL RESOURCE RECOVERY ASSOCIATION

JUNE 3, 1986

TESTIMONY
W. Wilson Goode
Mayor of Philadelphia
Senate Committee on Energy and Natural Resources

An effective and enforceable national policy which requires utilities to buy at a reasonable cost the power produced by small power producers and cogeneraters is not only sound energy policy but critical to the waste management challenges facing this nation. This message, if no other, is essential for this Committee to hear.

Today, our country is being strangled by its own solid waste and sewage sludges. Particularly in the more densely populated regions, waste management options are becoming more limited as landfills close and become more remote. The predominant solution being adopted across the United States is the development of trash-to-energy plants. These plants burn trash and use the heat to produce useful steam and/or electricity. Another application of resource recovery involves the use of sewage sludge gases as a fuel source. These facilities are qualifying facilities under the Public Utility Regulatory Policy Act of 1978 (PURPA), as they use a waste product as fuel and frequently can be designed to cogenerate both electricity and usable steam. Since these trash-to-energy plants are qualifying facilities, electric utilities are required to buy the associated electricity at the utility's avoided cost. The requirement to buy this power at a prescribed price is necessary if these projects are to be economically viable. Without these requirements many utilities would not offer to buy this power at any price, crippling the development of another domestic energy source and the quest for a solution to this nation's waste management crisis.

In Philadelphia, as many local solutions have been exhausted, the cost of trash disposal has sky rocketted. In 1981 the cost of trash disposal was about $20 per ton. Today the cost is $54 per ton, and rising. The residents and businesses in the City simply cannot afford this price escalation. In an effort to reverse this trend, the City is planning to build a trash-to-energy plant which will handle 630,000 tons of trash per year. This plant is designed to produce electricity, which we currently plan to sell to the local investor-owned electric utility, and steam, which we plan to sell to the Philadelphia Navy Yard. The operating cost of this facility (in 1986 dollars) is $37 million/year. About $12 million of these costs should be offset by revenues from the sale of electricity to the power company. If all goes as planned, this answer to Philadelphia's refuse management problem should allow the cost of trash disposal to stabilize at about $50/ton. Although this price is significantly higher than recent historic levels, and even more expensive than current trash disposal costs being experienced elsewhere, this trash-to-energy plant will provide the City with a reasonable and reliable refuse management system, within the City's control and at a predictable cost.

Philadelphia is not alone. Across this Nation, cities, counties, townships - even states are committing and relying upon trash-to-energy plants as a mainstay of their refuse management systems. For example, the core of Conneticut's and New Jersey's waste management policies is resource recovery systems. Additionally, trash-to-energy facilities are being built or are planned in Alabama, Calfornia, District of Columbia, Florida, Georgia, Hawai, Idaho, Indiana, Kentucky, Maine, Maryland, Massachuessetts, Michigan, Minnesota, Missori, Montana, Nevada, New Hampshire, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, Pennsylvania, Puerto Rico, Rhode Island, Tennessee, Texas, Utah, Vermont, Virginia and Washington. The cost effectiveness of each of these trash-to-energy plants depends upon there being a fair market for the energy.

What must be done? First and foremost, no change should be considered which would lessen a utility's obligation to buy energy produced by a qualified facility. Since the implementation of PURPA there has been an infusion of privately produced power, nationally. One of the reasons for this is that there had been a great deal of penned-up potential for private power production. This was caused by the pre-PURPA environment in which the market for excess electricity was uncertain and unfair. Many utilites simply refused to purchase the electricity while others offered low payments based on average fuel costs and not total incremental costs. There are still today utilites who feel threatened by private power production and would refuse to deal in good faith with qualifying facilities were they not required to by law. If trash to energy is to be a viable part of our refuse management system the market place for the electricity created by PURPA must be maintained.

Second, the avoided cost principle is sound policy. It makes sense for a utility to pay what the utility would otherwise have to pay for its power. The definition of avoided cost may vary across the country due to power pool arrangements, the need for capacity, government involvement in utility planning, local laws, etc, but the basic premise that utilities should pay full avoided costs still stands. Cities should not subsidize utilities nor should utilities subsidize waste management. Avoided cost pricing achieves this balance. As a prospective energy producer it is important that we know that we will be paid fairly for what we deliver. Every mil per kilowatthour is important to the economics of a private power project. As stated earlier, at full avoided energy costs the City would receive about $12 million annually for the electricity generated by its trash-to-energy facility. Every tenth of cent per kolowatt hour reduction in the anticipated payments would cost the City over a quarter of a million dollars annually and would increase the cost of trash disposal by 40¢ to 45¢ per ton. A one penny per kilowatthour decrease in the price paid for this electricity would increase the cost of trash disposal by $4.00 to $4.50 per ton.

The City of Philadelphia is not going to get rich through this trash-to-energy venture. Even if avoided costs were double those used in our current calculations, the cost of trash disposal would be approximately $30/ton, still higher than our costs in 1984. Trash-to-energy is not a get rich scheme for the myriad of localities which will depend upon it over the years to come. It is a prudent but still costly solution to our growing refuse management crisis.

There are some issues which this Committee could address which would help solve some of the ongoing debates surrounding private power production: 1) Utilities should be required to buy whatever power is offered to them by a qualifying facility. Currently, some utilities offer to buy either all or none of the power produced by a qualifying facility (QF). The QF is therefore arbitraliy restricted from selling some of the production to other potential buyers. The QF should be permitted to sell their electricity to anyone, consistent with local public utility laws and regulations. We recognize that different rates should be paid for different types of power (e.g. firm power versus non-firm power). 2) Both utilites and private power producers should be encouraged, and if need be required, to enter into long term contracts which reflect the useful life of the facility, the utilities long term avoided costs, prudent balancing of risk, and provides for long term reliability and stability. 3) Utilities should be required to wheel (i.e. provide transmission service) private power production at reasonable rates, subject to the availability of the transmission and distribution system. The monopoly franshise and eminant domain rights afforded to a utility's transmission and distribution system should carry an obligation to provide service. Mandatory wheeling increases the market place for private power production, and allows for power to be delivered to where it is most needed, as limited by the cost of wheeling.

The same individuals who try to point out the "problems" with private power production, often say that if the utilities do not invest in new plants today that there will be energy shortages in the late 1990's. Trash-to-energy and other resource recovery facilities have a place in this nation's energy future. Many will try to alarm you by telling you how many megawatts of private power production may be developed if PURPA is not changed. What should be alarming is that these resources have laid idle for so long. If trash-to-energy and sludge-to-energy plants had been feasible before PURPA corrected many of the regulatory environment and market inequities this nation's waste management problem would not have yet arrived.

I look forward to addressing this Committee in person as you focus on this important issue. The issues being addressed by municipalities through the nation as they relate to PURPA must not be overlooked as you revisit this important piece of legislation.

STATE OF CALIFORNIA—THE RESOURCES AGENCY
GEORGE DEUKMEJIAN, Governor

CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET
SACRAMENTO, CALIFORNIA 95814

916-324-3259

July 7, 1986

Senator James A. McClure
SD-361 Dirksen Senate Office Building
Washington, D.C. 20510

Dear Senator McClure:

Thank you for allowing the California Energy Commission to express its views on the implementation of the Public Utility Regulatory Policy Act. The alternative energy supplies that were created by PURPA have presented California with significant opportunities and challenges, which we have described in the attached statement.

We would like the attached statement to be included in the record of your June 3 and 5, 1986 hearings. Please call us if you have questions.

Sincerely,

Charles R. Imbrecht
Chairman

Barbara Crowley
Vice Chair

Warren D. Noteware
Commissioner

STATEMENT BEFORE THE SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

EFFECTS OF PURPA ON COGENERATION DEVELOPMENT IN CALIFORNIA

California Energy Commission
June 5, 1986

In recent years California has experienced a boom in small power development, primarily cogeneration. A significant incentive to cogenerators has been the avoided cost payments required by PURPA. The Energy Commission encourages development of small power production, and in fact our forecasts call for 25 percent of future supplies to be met by renewable and cogeneration facilities. While the California Energy Commission supports development of Qualifying Facilities, we now may have more power than can economically be incorporated into the utility system. As a result we are trying to provide for orderly development of these important resources.

The purpose of this statement is to describe the current situation in California for power plants sited by the Energy Commission. We do not believe that the current situation warrants amending PURPA, but there does need to be an understanding of the potential conflicts that can arise with avoided cost pricing.

The effects of PURPA are of interest to the Commission because the CEC is the permitting agency for all thermal power plants over 50 MW in California. Currently the Commission is reviewing 12 applications for 2,072 MW of projects that are over 50 MW. In addition, in the next year we are expecting 9 applications for about 1,100 MW. Most of these projects are gas-fired cogeneration, but there are also several municipal solid waste-to-energy projects. All of these projects qualify for long-term avoided cost contracts under PURPA. In conducting our review of proposed projects, we examine the environmental effects and the need for projects in relation to forecasted demand.

To facilitate this review the Commission adopts a biennial Electricity Report that includes a 20 year forecast of electrical demand by utility and a forecast of likely supplies, including QFs less than 50 MW. The result is an integrated assessment of the need for power supplies taking into account both the availability and desirability of various supply resources by technology, fuel type, costs, and environmental impacts. The policies and forecasts in the Electricity Report guide the siting process.

The Commission is concerned about the quantity and cost of power from the large number of QF proposals. With more QF development than we had anticipated, it appears that there will be more power than would be needed "to keep the lights on," and also more power than is needed in view of cheaper alternatives.

The problem has arisen because the avoided cost prices were set without adequately considering the supply response of developers or the actual needs of the utilities. No one, including the Energy Commission, anticipated that over 11,000 MW of QFs would sign contracts. In view of the supply response, the prices that utilities must pay to those QFS that signed contracts in 1984 and 1985 are significantly above actual or projected avoided costs. Since the contracts are long-term "take or pay" contracts the consequences of these contracts are significant, since they preclude utility flexibility to buy cheaper power when it is available. As a result, the Commission is facing the difficult task of trying to evaluate the need for these plants in view of the potential negative effects on ratepayers from too much high cost energy.

Currently there is widespread acknowledgement that the avoided costs in the signed QF contracts are too high, and the question is whether the ratepayers should be compelled to live with the consequences. The Commission faces a dilemma between its legislative mandate to balance the need for power plants against environmental impacts, and the apparent Federal mandate to allow all QF development that has an avoided cost contract and that meets minimum efficiency requirements.

One way to achieve a better match between the utility's need for power and the potential surplus of QF power is to have the QF's and utilities include within their contracts provisions for utility dispatch of the project when cheaper supplies are available. The problem of potential oversupply can also be addressed if the Commission delays or conditions its approval of these projects being operational at some year in the future when the power would be needed. The Commission also feels that it should be able to approve only those projects that are the least expensive and the most efficient.

The QF applicants feel that PURPA preempts the state jurisdiction to examine need or efficiency. They also feel that if they have a signed contract based on avoided costs then need should not be an issue, since ratepayers, by definition, should be indifferent to QF-supplied power or utility-supplied power if the avoided costs are set correctly.

The preemption issue may ultimately be tested in the courts. The cost issue relies on the ability of state ratemaking agencies to set avoided costs correctly. Estimating avoided costs and setting contract terms that translate them into workable contracts is very difficult. The California Public Utilities Commission sets avoided cost contracts for investor-owned utilities in California, and it established the original contracts with Energy Commission support. However, while it may be theoretically correct that ratepayers are indifferent if avoided costs are paid to QFs, it is apparent that administratively set long-term avoided costs are quite likely going to be wrong simply because our ability to forecast is not perfect. If the forecast results in QFs being paid too much, then ratepayers are hurt, and if QFs are paid too little, then we will have less QF power than would be economically efficient. Future long-term contracts should provide pricing flexibility and dispatchability provisions to mitigate these risks.

California is committed to developing alternative supplies of electricity. But we must also insure that the most efficient and most economical projects are built. We also must have diversity in new power supplies and not, through an abundance of gas-fired cogeneration, recreate a dependence on fossil fuels that we have worked very hard to overcome.

DEPARTMENT OF NATURAL RESOURCES
AND CONSERVATION

TED SCHWINDEN, GOVERNOR
1520 EAST SIXTH AVENUE

STATE OF MONTANA

DIRECTOR'S OFFICE (406) 444-6699
HELENA, MONTANA 59620

June 23, 1986

The Honorable James A. McLure, Chairman
Energy and Natural Resources Committee
Dirksen Senate Office Building - Room 358
Washington, D.C. 20510

Dear Honorable Senator McLure:

Please consider the enclosed testimony of the Montana Department of Natural Resources and Conservation in your deliberations on PURPA. Should you have any questions regarding our testimony, please contact our Senior Economist, Larry Nordell, at 406-444-6697.

Sincerely,

Larry Fasbender

Larry Fasbender
Director

LF/jb
Encs.

DEPARTMENT OF NATURAL RESOURCES
AND CONSERVATION

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SUBMITTED TO
CONGRESS OF THE UNITED STATES
SUBCOMMITTEE ON ENERGY CONSERVATION AND POWER
JUNE 11, 1986

TESTIMONY OF THE MONTANA DEPARTMENT OF NATURAL RESOURCES AND CONSERVATION

One of the responsibilities of the Montana Department of Natural Resources and Conservation is monitoring energy issues that affect the welfare of the state and its citizens. In this context we are very interested in the outcome of these hearings. The main point we wish to make is that PURPA, or the rules implementing PURPA, should require the use of an avoided cost methodology that accounts for whether a utility is in a surplus or deficit load-resource balance. In particular, the cost of new capacity requirements in the future must be discounted to properly calculate avoided cost rates.

Montana has followed the progress of PURPA since the passage of the National Energy Act in 1978. Our state has been a major focus of interest on the part of wind and small hydro developers. We think PURPA is basically a good act. Nevertheless, it could be improved. We welcome this opportunity to provide Congress with our suggestions for some changes that would improve the way PURPA resources are acquired by utilities to serve their customers' loads.

In our view, the purpose of PURPA is to ensure that decentralized generating technologies could compete fairly with traditional utility central station generating technologies. If wind, small hydro, photovoltaics, and other small scale technologies can produce electricity at a cost less than that of large coal or nuclear power plants, then society would be better off relying of large coal or nuclear power plants, then society would be better off relying on the cheaper facilities to meet its future needs. PURPA stemmed from the idea that utilities were not receptive to constructing decentralized generating resources or to purchasing power from independent owners of small facilities.

To redress this imbalance between large and small-plants and between utility and independent power developers, PURPA established a mechanism of requiring utilities to purchase power from small facilities that met certain qualifying criteria. PURPA requires that the rates for these purchases be based on the costs utilities avoid by using the Qualifying Facility (QF) power rather than building new plants or running existing ones. The rates for each utility are set by state regulatory commissions. PURPA's requirement of setting rates equal to avoided costs is intended to ensure that utility ratepayers are not penalized. Total costs to the utility and its customers should be no greater under PURPA than what they would have been without the QF resources.

By some criteria PURPA has worked well. Utilities have contracted for significant amounts of QF resources. Hundreds of small power and cogeneration developers have built or are planning facilities that will take the place of or defer central station power projects.

However, significant problems remain that should be corrected. These problems rest mainly with the way PURPA has been implemented rather than with the act itself. In the years since its passage, PURPA has become a tool for accomplishing goals for which it was not intended. An example of this is the use of PURPA avoided cost rates to promote renewable energy, without regard for the utility's need for new generation.

Whatever the intrinsic qualities of renewable resources, PURPA should not be used to promote renewable energy sources at the expense of ratepayers. This was clearly not the intent of Congress. The clamor by PURPA resource developers and renewable energy enthusiasts for higher avoided cost rates, regardless of a utility's load-resource balances, may be understandable given their self interest. Nevertheless, this clearly goes beyond the PURPA goal of simply giving small power facilities an even chance at supplying consumer loads in utility service areas if they can produce power at the same cost or less.

When new capacity is needed to meet customer demand in a utility's service area, the new resource that should be acquired is that with the lowest combined capacity and operating cost. When new capacity is not needed in the foreseeable future, a PURPA resource would only displace operation of existing plants so that the only avoided cost would be the operating cost of existing plants. For a utility that will need additional capacity in the near future, the avoided cost is a combination of the operating costs of existing plants that would be avoided and the value of deferring investment in a new utility-owned generating facility. Thus avoided cost, which is the value of PURPA resources to society, depends on whether a utility is in surplus and how long that surplus is expected to last.

Problems have arisen from utility commissions trying to apply rate base methodology to compute avoided cost. This causes problems because rates to customers and PURPA rates have two very different functions. Customer rates are primarily designed for the recovery of costs that a utility has already committed itself to incur. Even when utility commissions apply a prudence test to past utility investments, rate making is primarily concerned with cost recovery and is therefore essentially backward looking. PURPA rates are intended to provide a price signal to influence investment in new plants, both QF resources and utility-owned resources. PURPA was intended to encourage the acquisition of resources with the lowest future costs, and PURPA rates should, therefore, be set in a forward looking process.

If normal rate base methodology is used to set PURPA rates for a utility that is in surplus, PURPA rates will be based on current operating costs and historic capacity costs. However, the actual avoided cost is the sum of operating cost and the value of deferring investment in future capacity. This means that PURPA rates will be too high and QF resources may be acquired before they are needed or they may have higher costs than facilities the utility could construct itself. In any case, the utility will pay more for QF resources than their value to the system. This will impose additional and unnecessary costs on ratepayers, utility stockholders or both.

For PURPA to work as intended, to avoid the misuses discussed here, and to work without adversely affecting ratepayers, the methodology used to calculate avoided costs for setting purchase rates must reflect the load resource balance of a utility. If the utility is in surplus, then avoided capacity costs must reflect the length of time before capacity additions are required. The proper way to do this is to require utility commissions to discount the capital costs of these future capacity additions when calculating the avoided cost for current PURPA resources.

This requirement would make PURPA work as intended. The more surplus or the farther in the future new resources are needed by a utility, the more the capital costs would be discounted indicating that new generating resources would be worth less to the system and the utilities would be required to pay less for PURPA facilities. Thus, as a utility moves closer to needing new resources, PURPA rates increase. Discounting properly reflects the value to the utility system of any resource, not just a PURPA resource. This we feel makes PURPA work as it was intended.

We urge that PURPA, or the rules administering it, be amended to require that avoided cost calculations discount the costs of future resource additions. This change would send the proper price signal to PURPA resource sponsors and would be neutral to utility ratepayers. This is the intent of PURPA and would reduce the criticisms of PURPA from both the utilities and PURPA resource sponsors.

NEW YORK STATE ENERGY OFFICE

WILLIAM D. COTTER
COMMISSIONER

June 19, 1986

Senator James McClure
Energy Committee
Room 358
Dirksen Office Building
Washington, D.C. 20510

ATTN: Gerry Hardy

Dear Senator McClure:

The New York State Energy Office offers these comments to be added to the record on the hearings on June 3 and 5, 1986 conducted by the Senate Committee on Energy and Natural Resources on the implementation of PURPA. Our comments provide additional perspectives in regard to the development of small power production facilities in New York State.

PURPA has had a significant impact on the development of small power production facilities in New York State. We view development of alternate energy facilities as part of an overall strategy to reduce New York State's dependence on imported fossil fuels, diversify the electric supply fuel mix, produce electricity in a more environmentally benign manner, promote economic development and defer the need for new electric capacity and thereby reduce the risks to ratepayers associated with the construction of new power plants.

The single, most important element resulting in increased alternate energy activity is the State's legislatively-mandated minimum purchase price of 6¢/Kwh for electricity sold by small power producers to electric utilities. This minimum price provides a firm basis for economic analysis of individual projects, provides an assured revenue stream and, perhaps as importantly, represents a State commitment to alternate energy projects.

Currently in New York, legislation has been introduced to raise the State's 6¢/Kwh minimum purchase price to 8¢/Kwh. We support such an increase as essential to the continued growth of small power production and to ensure that the State continues to enjoy the fuel diversification, economic development and environmental benefits of alternate energy forms. Some have opposed this legislation on the grounds that it will be too costly to the electric utility ratepayers. The SEO does not agree, but in any event, this debate is properly conducted at the state level.

TWO ROCKEFELLER PLAZA • ALBANY, NEW YORK 12223

It is important that states maintain the right to enact provisions which provide additional benefits to small power production facilities beyond those contained in PURPA and FERC's implementing regulations. This allows individual states the flexibility to develop and implement energy strategies tailored for their unique circumstances. The provisions of PURPA and FERC's regulations allowing state latitude in implementation of this important law should not be changed.

PURPA remains a significant, far-reaching law which has helped reorient electricity supplies away from large, central station power plants to smaller, more diversified facilities using renewable resources or traditional fuels in a more efficient manner. We urge that this landmark legislation not be weakened, and that it continue to allow states wide latitude in implementation.

Cordially,

William D. Cotter

William D. Cotter
Commissioner

WDC/bmm

RICHARD H. WATSON
Director

STATE OF WASHINGTON
WASHINGTON STATE ENERGY OFFICE
400 E. Union, 1st Floor, ER-11 • Olympia, Washington 98504 • (206) 754-0700

May 16, 1986

The Honorable James McClure
Committee on Energy and Natural Resources
Dirksen Senate Office Building, Room SD-358
Washington, DC 20510

Re: Public Utility Regulatory Policies Act (PURPA) Oversight Hearings

Dear Senator McClure:

I am offering these comments so that the Committee on Energy and Natural Resources can gain an insight into the role played by PURPA and small hydroelectric projects in meeting Washington's requirements for electrical energy and capacity. PURPA did trigger a permitting gold rush - which produced many feasibility studies and resulted in the identification of many cost-effective and environmentally acceptable hydropower sites. Overall, it was a positive outcome which facilitated regional planning and allowed resource "supply curves" to be constructed. Few projects have been constructed, in large part because PURPA based avoided costs provided feedback to developers such that an appropriate "build/don't build" decision was made. To date, PURPA has served our state well, even during periods of electricity surplus, by serving as a flexible tool which provides the price signals necessary for resource development decision making.

The Gold Rush Revisited

Washington State has significant water resources - the 1975 Catalog of Washington Streams and Salmon Utilization identifies 13,995 rivers or streams, comprising 25,000 stream miles in Washington's coastal zone and Puget Sound basins alone. Thus, it is not surprising that a significant number of applications for hydropower development have been filed with the appropriate regulatory agencies. The vast majority of applications are, however, completely speculative in nature.

The May, 1985, Department of Ecology "Washington FERC Database" contains 716 entries. In addition to 16 already licensed and operating hydropower projects, the database includes a large number of sites for which preliminary permits have already been canceled, surrendered, or denied (due to competing applications for the same site). Over 200 preliminary permit applications have been filed by just four developers (Lawrence McMurtrey (95), WP, Inc. (61), Energenics (24), and the Town of Skykomish (19)). None of the four have completed a hydropower project within Washington State.

Speculating in hydroelectric sites is akin to speculation in mining claims. The permitting entry costs are low (no cost for a preliminary permit application, typically $5 for a mining claim), and the potential benefits are thought to be substantial. Both industries are heavily regulated, and require substantial up-front development costs. The risks incurred are high, and few developers actually "strike it rich."

The Bureau of Land Management reports that 8,449 mining claims were filed on federal lands in Washington State in fiscal year 1984. Chelan County alone had 6,558 and 2,718 recorded claims in calendar years 1983 and 1984, respectively. While the impacts of developing these claims would be staggering, requiring access roads, power, water supplies and wastewater treatment; little regulatory agency concern is expressed because it is acknowledged that the claims are speculative. Yet, the same agencies, in making arguments for increased regulatory controls or for cumulative impact studies of hydropower development, refuse to consider the speculative nature inherent within the licensing process and the industry itself. Potential environmental damages are thus greatly overstated, while the ability of existing regulatory controls to require incorporation of mitigation techniques into project designs is frequently ignored.

Recent Small Scale Hydroelectric Project Development

While the number of hydroelectric project applications remains high, relatively few small hydropower projects have been constructed. Eighteen small-scale projects, comprising 70,220 kilowatts of generating capacity have come on-line or commenced construction in Washington State since 1980 (see Table 1). The aggregate installed cost for these projects, while not monitored by our office, likely exceeds $100 million.

Seven of these eighteen projects are located at irrigation structures, two are on municipal or industrial water supply pipelines, another two represent expansions of existing generating facilities, and three involve the refurbishment of abandoned hydroelectric sites. Thus, there is a grand total of four new, high head run-of-the-river hydroelectric projects in Washington State. Two of the four projects have diversion dams, which between 4 and 6 feet in height, while the third uses a unique submerged intake concept. All of the run-of-river projects are on high gradient stream reaches which do not support runs of anadromous fish.

PURPA: Giving the Proper Signals

By its very nature, PURPA operates best during a period of electrical surplus. Avoided costs, based on the construction and operation of large scale thermal facilities, cannot be captured unless the large generating plants are, in fact, avoided. Due to the long lead time involved in the design, licensing, and construction of thermal projects, an electrical energy surplus of at least 6 to 7 years should be maintained to defer critical path construction decisions.

With a modest two percent growth rate in electrical consumption, our region will cease to be "awash in electricity," in five short years (see Figure 1). Electrical growth rates have been shown to be closely correlated with northwest economic activity and actually approached 3 percent as late as 1984 (see Figure 2).

PURPA is a useful and necessary tool, providing price feedback which enables utilities, renewables, and cogeneration developers to make appropriate resource development decisions. How do the avoided cost price signals work? As the avoided thermal plant is deferred further into the future due to buildup of an electrical surplus, the construction and operating costs are increasingly discounted. This progressive discounting of future expenditures into present value dollars automatically adjusts utility avoided costs to reflect the need for constructing new resources.

The price signal conferred through avoided cost tariffs depend on a utilities' load projections, capacity expansion plans and existing generating mix, fuel prices, hydropower availability, and the opportunity to purchase surplus energy from other utilities or federal power marketing agencies. The avoided costs for the Puget Sound Power & Light Company for the summer of 1985 winter 1985-86 period, shown in Table 2, dramatically illustrate the self-correcting response of the utility's reported avoided costs to a decrease in forecasted rate of load growth. This avoided cost price signal, by rapidly responding to predicted changes in utility needs, forced developers to make a correct "no-build" decision. The catastrophic consequences of overbuilding, thermal project deferral, and/or outright termination, which have plagued the northwest region in the recent past, thus did not occur.

The avoided cost concept is very useful to utilities or regions which must make decisions in the face of load growth or thermal project cost uncertainties. Avoided costs are easily and continuously updatable, and provide the information necessary for management and development decisions to be made. Avoided costs are more flexible than conservation standards or building codes which tend to "lock in" criteria based on a fixed set of economic assumptions. Finally, the risks and benefits of signing a power purchase contract at a rate based upon projected avoided costs are shared between developer and utility. If load growth occurs at a greater than anticipated rate, avoided costs will rise and the developer with a 30 year levelized or fixed price contract will "lose." The utility will "win." Conversely, if predicted rates of load growth or fuel price increases do not occur, the developer with a fixed price contract is protected, and the utility is the "loser." The magnitude and time duration of the utility loss is much less, however, than for a thermal plant investment.

Power Purchase Contracts: Is the Price Right?

The rate paid to hydropower developers for purchased electrical energy and capacity is negotiated based upon the utility's projected avoided costs. The rate is dependent upon such parameters as duration of the power purchase contract, seasonality of electricity production, project reliability, peaking or capacity capability, buyout provisions, and project size. Some Washington project developers have elected not to sign long-term contracts, and sell to their local utilities at their current reported avoided cost. For instance, Gordon Foster sold output from the 270 kW Deep Creek project to Washington Water Power for 2.7¢/kWh. John Craft is willing to sell energy from the 1505 kW Lilliwaup project to Mason County PUD for the same price they pay the Bonneville Power Administration for energy and capacity - currently around 2.2¢/kWh. These developers have not signed long-term binding contracts because they believe that avoided costs will increase in the near future.

Other developers have negotiated long term fixed price or levelized contracts that pay more than the current avoided costs at the front end. This contracting format is advantageous to both developer and utility as an assured energy price allows the developer to cover early debt service and operating costs. The utility benefits in the long term as they are assured of a constant supply of relatively low-priced energy. Output from the 1,850 kW Rocky Brook Creek project will be sold to Seattle City Light at a 10 year fixed price of 4.8 and 2.5¢/kWh in the winter and summer, respectively. Robert Shipp is selling electricity from his 900 kW Bellingham water pipeline project to Puget Power at winter and summer rates of 4.5 and 2.7¢/kWh, respectively. His contract terms are fixed for 20 years. Shipp is also selling output from his 120 kW Smith Creek project to Puget Power for 4.5 and 2.0¢/kWh during the winter and summer, respectively, under a 10-year fixed price contract.

Three other projects have entered into 35 year fixed price contracts. Glen Phillips' 1,500 kW eastern Washington spring snowmelt peaking Big Sheep Creek project is selling electricity to the Washington Water Power Company for an average price of 4.5¢/kWh. The South Fork Associates' recently licensed 20 MW Twin Falls and 3.4 MW Weeks Falls projects, when completed, will sell energy to Puget Power for 7.5¢/kWh.

It is apparent that a wide range of contractual terms and conditions are possible. In general, it can be argued that Washington utilities have entered into attractive and cost-effective power purchase contracts. Seattle City Light was not, in fact, obligated to purchase the Rocky Brook Creek output as the site does not lie within their service territory. The project output was purchased as it represents a cost effective acquisition for the utility. Terms for various utility power purchase contracts are summarized in Table 3.

Environmental Considerations and Constraints

It has been said that next to nuclear power, hydropower is our most heavily regulated technology. This is an entirely believable statement as project proponents face an array of federal, state and local requirements. Anadromous fisheries interests are protected by the National Marine Fisheries Service, U.S. Fish & Wildlife Service, and the Washington Department of Fisheries. Resident fish and wildlife fall under the purview of the Washington Department of Game.

The Department of Ecology issues permits to Appropriate Public Waters (a water right), a Reservoir Permit and Dam Safety Approval, a water quality certification, the Flood Control Zone Permit, and in consultation with the Department of Fisheries and Game, a Hydraulic Project Approval. The Office of Archaeology and Historic Preservation provides an archaeological approval, while the Department of Natural Resources oversees construction on forested, non-federal lands. The U.S. Forest Service requires a Special Use Permit for projects on federal lands.

Additional permits may be required from the Army Corps of Engineers, County Planning Department (Shoreline Substantial Development and Zoning Conditional Use Permits), County Department of Public Works (surface water draining plan approval, grading and utility permits), and the County Building Department. The State Department of Social &

Health Services must give approval if the project involves a public water supply, and the U.S. Environmental Protection Agency regulates water quality and pollutant discharges.

Small scale hydropower developers have found that it often takes twice as long to license a project as it takes to complete construction. Without a doubt, the public and environmental interests are vigorously defended through the entire hydropower licensing procedure. Projects win approval only after minimum instream flows which protect instream values are established; sedimentation plans are approved; and fish screening and passage concerns are resolved.

I hope this information proves useful in your assessment of the effectiveness of PURPA. Don't hesitate to contact Gil McCoy of my staff at (206) 586-5053, if you require additional information or clarification.

Sincerely,

Richard H. Watson

Richard H. Watson
Director

C-L21-13

Attachments

cc: Gerry Hardy
Jan Boettcher, NW Small Hydroelectric Assoc.
Congressional Delegation

RHW/mwj
C-L21-13

Table 1

On-Line or Under Construction Small Scale Hydropower Projects Since 1980, Washington State

	Project Name	Sponsor	Purchasing Utility	Project Type	Generating Capacity, kW
1.	Russell Smith	S. Columbia Basin Irrigation Dist. (SCBID)	SCL/TCL	I	6,200
2.	Port Townsend Mill	Crown Zellerbach Corp.	PSP & L	M	375
3.	Woods Creek	Woods Creek, Inc.	Sno. Co. PUD	R	650
4.	Smith Creek	Robert Shipp	PSP & L	N	120
5.	Mill Creek	L. Walker/Lewis County PUD	Lewis Co. PUD	N	600
6.	Eltopia Branch Canal	SCBID	SCL/TCL	I	2,200
7.	P.E.C 66	SCBID	SCL/TCL	I	2,400
8.	Quincy Chute	Quincy Columbia Basin Irrigation Dist.	Grant Co. PUD	I	9,400
9.	Deep Creek	Gordon Foster	WWP	R	270
10.	Bellingham Water Supply Pipeline	Robert Shipp	PSP & L	M	900
11.	Upriver Dam	City of Spokane	WWP	E	13,100
12.	Cowiche	Yakima-Tieton Irrigation Dist.	PP & L	I	1,500
13.	Orchard Avenue	Yakima-Tieton Irrigation Dist.	PP& L	I	1,450
14.	Rocky Brook Creek	Joe Clarkson, Weatherly Associates	SCL	N	1,850
15.	Lilliwaup Falls	John Craft	Mason Co. PUD	E	1,505
16.	Main Canal Headworks	SCBID	SCL/TCL	I	26,000
17.	Big Sheep Creek	Glenn Phillips	WWP	N	1,500
18.	Falls Creek	Gus Haley	Clallam Co. PUD	R	200
				TOTAL	70,220

Purchasing Utility Code

SCL/TCL: Seattle & Tacoma City Light Depts.
PSP & L: Puget Sound Power & Light Co.
WWP: Washington Water Power Co.
PP & L: Pacific Power & Light

Project Type

Code: I = Irrigation dam, drop structure or wasteway
M = Municipal or industrial water supply conduit
E = Expansion of existing power dam
R = Refurbishment of abandoned site
N = New high head run-of-the-river project

Table 2

Avoided Costs, cents/kWh
Puget Sound Power & Light Company

Date Avoided Cost Projection Was Made	Average Streamflow Conditions Summer 1985	Average Streamflow Conditions Winter 1985-86
1980	4.69	7.18
1982	2.12	3.51
1983	1.72	2.51
1984	1.22	2.36

Table 3

Power Purchase Contract Terms
Washington State

Project Name	Winter Rate kWh	Summer Rate/ kWh	Contract Duration years	Purchasing Utility
Port Townsend Mill	5.0	5.0	5	PSP & L
Woods Creek	BPA PF Rate[1]		1	Sno. Co. PUD
Smith Creek	4.5	2.0	10	PSP & L
Deep Creek	2.7	2.7	1	WWP
Bellingham Water Supply Pipeline	4.5	2.7	20	PSP & L
Rocky Brook Creek	4.8	2.5	10	SCL
Lilliwaup Falls	BPA PF Rate[1]		1	Mason Co. PUD
Big Sheep Creek	4.7	4.7	35	WWP
Twin Falls	7.5	7.5	35	PSP & L
Cowiche & Orchard Ave.	1.85[2]		20	PP & L

1 - The current BPA PF rate for energy and capacity is approximately 2.2¢/kWh.
2 - Escalates to 3.1 by 1993, increase to 8.1 in 1994, escalates to 11.11 by 2005

Figure 1

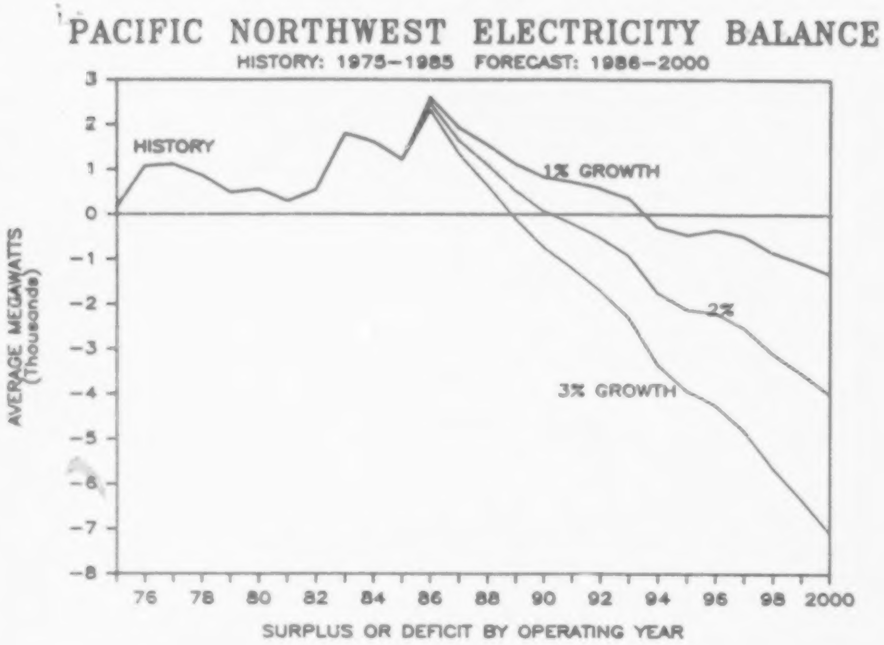
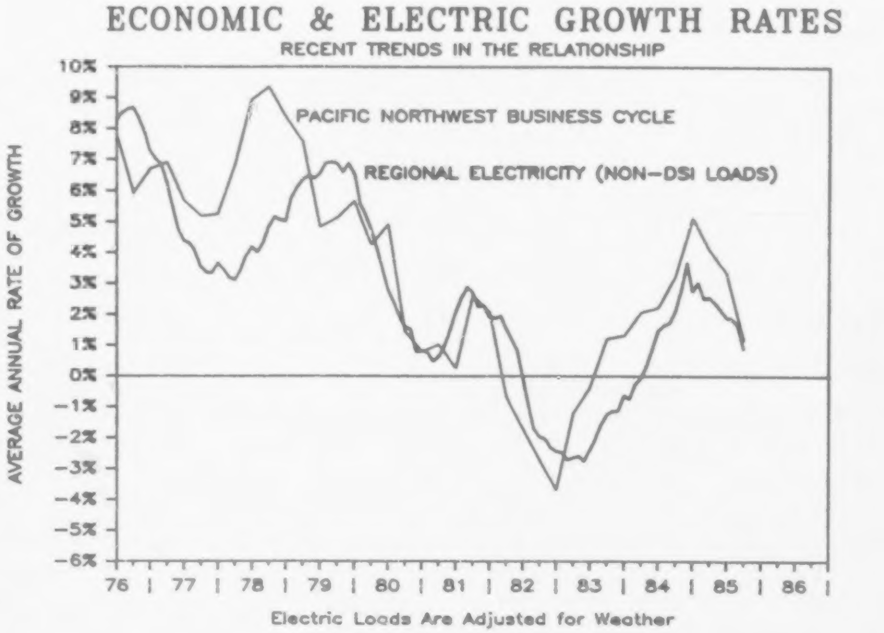


Figure 2



STATEMENT OF
THE AMERICAN GAS ASSOCIATION
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
ON THE
PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978
June 30, 1986

The American Gas Association (A.G.A.) is pleased to submit for the record its statement in support of cogeneration and small power production under Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). A.G.A. is a national trade association comprised of nearly 300 natural gas distribution and transmission companies whose members account for nearly 85 percent of the nation's total annual gas utility sales.

Collectively, the natural gas industry services more than 166 million consumers in all 50 states. Many A.G.A. member companies transport or sell gas for industrial and commercial cogeneration. Gas-fueled cogeneration systems currently consume over 700 Billion Cubic Feet (Bcf) of gas annually (nearly 4 percent of total annual gas consumption). If all planned cogeneration systems are built, cogeneration will consume an additional 600 Bcf of gas.[1]

Section 210 of PURPA has been critical to the success that cogeneration has enjoyed in recent years. Section 210 required the Federal Energy Regulatory Commission (FERC) to prescribe a rule compelling electric utilities to: (a) sell electricity to qualifying cogenerators at just and reasonable rates; and (b) purchase electricity from cogenerators at just and reasonable rates, not to exceed the incremental cost of alternative electric energy (otherwise known as "avoided cost"). These provisions were enacted to ensure that cogenerators and small power producers received fair treatment by electric utilities.

We will to discuss the following issues:

- The primary objectives of PURPA--developing cogeneration and small power production, promoting electricity conservation along with efficient electricity production and efficient resource utilization, and providing equitable electric rates--are largely being achieved. Most parties agree with the basic tenets of PURPA, including the concept of avoided costs, although there is valid disagreement over how the legislation is being implemented by both the FERC and some state agencies.

- The avoided cost principle is sound, and if correctly calculated and applied, it will promote ratepayer benefits.

- The electric utility industry will need small, clean, efficient, low lead time, less capital intensive sources of electric power production to ensure system reliability into the 1990s. As long as the Fuel Use Act blocks utilities from pursuing gas-fired combined cycle generation of their own, purchasing cogenerated power is one of the few real cost-effective options available to electric utilities.

- Cogeneration also provides a variety of external benefits, including the potential for major reductions in the generation of air and solid waste pollution. In addition, it enhances the competitive position of U.S. firms in the international market, while also counteracting the sluggish demand for natural gas that has forced some 300,000 employees out of work in the exploration and production industry.

- The natural gas market is largely deregulated today, in sharp contrast to the situation when PURPA was enacted. As a result, the natural gas needed to fuel cogeneration facilities will be supplied in the amounts and at the price determined by the market. There is no longer a need to question the gas resource base.
- Issues such as avoided cost, standby charges, and wheeling should be determined ultimately at the state level. Increased guidance and data collection, however, should be provided by FERC.

PURPA Goals Are Being Achieved

The intent of PURPA was to develop cogeneration and small power production while promoting electricity conservation, electricity production efficiency and resource efficiency, and the providing equitable electric rates. There has been little disagreement in the testimony presented to this Committee as to the validity of these goals, although some commenters have placed different relative values on the individual goals. In fact, most commenters agree that all of the goals are being met, although there is certainly debate over the degree to which goals are being, or could be met.

The rebirth of cogeneration as a significant contributor to this nation's electricity supply is obviously highly correlated to the passage of PURPA. Cogeneration provided about half of all our electricity in 1900, but its share steadily declined to less than 5 percent in the 1970s as a result of the evolution of large central station power production. Today about 7 percent of all electricity produced in the U.S. is through cogeneration, and this share could double by the end of the century. To date, over 2,500 facilities with a combined capacity of nearly 40,000 megawatts (MW) have filed with the Federal Energy Regulatory Commission (FERC) for qualifying facility status. The volume of petition filings has been increasing steadily. In terms of the importance of cogeneration to the natural-gas industry, those systems built, under construction, or on order, account for over 700 Bcf of gas annually (nearly 4 percent of total annual gas consumption), and planned systems could increase this volume by 600 Bcf per year.

Similar to the goal of cogeneration promotion, there is little argument with respect to the success of PURPA in enhancing efficient resource utilization. About two-thirds of the energy consumed in conventional electric power production is lost as waste heat, in contrast to cogeneration systems, which can capture and use over 70 percent of the energy consumed. A gas turbine cogeneration system, for example, would require about 25 percent less input energy than the combination of a new coal-fired electric powerplant and an oil-fired boiler producing steam. Energy efficiency translates directly into energy conservation. For example, if all facilities that have filed with FERC for qualifying facility status (approximately 40,000 MW) become operational, the energy savings will be roughly equal to 400,000 barrels of oil per day, nearly 1 quad per year.

The goal of electricity conservation is often overlooked in discussions on cogeneration, but it too is served well by the technology. Many cogenerators consume the power produced on site, thereby eliminating the transmission losses inherent with the distribution of electricity from a central powerplant--roughly 9 percent of all electricity generated. In addition, most cogeneration facilities operate on natural gas or oil, and, therefore, they are not required to include the costly energy consuming pollution control equipment which new coal-fired electric powerplants must install. Such equipment consumes about 3 percent of all electricity produced. Thus, a new coal-fired central station powerplant will provide about 12 percent less energy to the ultimate consumer than a gas- or oil-fired cogeneration facility consuming the electricity produced on site.

The goal of ratepayer equity is the most hotly contested of the four primary PURPA goals, with the bulk of the debate focused on the issue of avoided costs as a standard for buyback rates. However, most parties, regardless of which side of the issue they are on, seem to be in general agreement with the avoided cost principle. The disagreement comes with how the avoided cost is calculated and applied. If a buyback rate is set equal to a correctly calculated and applied avoided cost, the ratepayer can be no worse off with cogeneration than without it--by definition.

Although the allegations of some commenters give the impression that it is common for utilities to purchase power from cogenerators at rates exceeding the avoided cost, it must be remembered that the avoided cost is the maximum statutory price that can be charged for cogenerated electricity. If the avoided cost established by the state commission does not reflect the "true" avoided cost, this is a matter for the cogenerator, utility and state commission to rectify with oversight guidance from FERC. The principle is not invalid in this case, only the implementation is lacking.

In fact, many cogenerators sell electricity to the grid well below the avoided cost. Although data on this point are lacking, we note the comment of Lawrence Anderson, the Director of FERC's Office of Electric Power Regulation in testimony provided to this Committee, that "It is my impression that many long-term contracts have been executed which provide for rates less than full avoided costs."[2] Further substantiating this point is a study prepared by Hagler, Bailly & Company for the DOE Office of Industrial Programs, entitled "Potential Detrimental Effects of Cogeneration Development on Utility Costs: A Preliminary

Assessment."[3] This study surveyed utilities that have a "relatively high level of buyback rates." In spite of this selection criteria, 3 of the 10 companies surveyed had buyback rates less than their average cost--far less than their incremental cost. The study also found that only 3 of 13 utilities--again in markets thought to be "pro-cogeneration"--received over 3 percent of their total electricity supply from cogenerators.

We urge FERC to increase its data gathering function in this area so that more quantitative results can be obtained. Nevertheless, we believe that the portion of cogenerated electricity being sold back to the grid is very small on most systems, and that power which is sold to the grid is often sold at rates below the avoided cost. According to Pfeffer, Lindsay & Associates for the U.S. Department of Energy, "Most large qualifying facilities must negotiate rates somewhat below full avoided cost to obtain concessions from the utility . . ."[4]

Reduce The Need For Coal and Nuclear Units

The period from the early 1960s through the mid-1970s was one in which a number of tenets were generally accepted by utility planners, energy forecasters, and policy makers: the demand for electricity was expected to increase at a steady and predictable rate; natural gas and oil were not considered viable options to fuel new electric utility plants due to price and availability expectations; and large, central station coal and nuclear units were assumed to be the most cost-effective means of generating electricity for the future. These tenets have been proven wrong in whole or in part.

The rapidly escalating capital costs of nuclear and coal-fired units, as well as various associated environmental and regulatory barriers, have diminished the attractiveness of these options. As a result of these and other factors, no new nuclear units have been ordered since 1978, and over 100 units have been cancelled. Similarly, the number of new coal-fired units projected to come on-line over the next decade has fallen steadily from 198 units projected in 1981 to only 107 units projected in 1984. In addition, the demand for electricity has become less predictable due to conservation, increasing fluctuations in the business cycle, and other factors. This uncertainty in electricity requirements along with long construction lead times and high real interest rates (well above inflation), makes large capital intensive coal and nuclear plants financially unattractive today.

The North American Electric Reliability Council (NERC) in its 1985 Reliability Review stresses the reluctance of utilities to proceed with new capital intensive coal and nuclear units. It notes that utilities are trying to avoid commitments to large power projects, since "Almost all the utilities now facing severe financial crises are in that situation because they have a large nuclear or coal unit under construction." Further, "Most utilities in good financial condition achieved that status by avoiding such projects or completing them several years ago."[5]

Because of the reluctance of electric utilities to commit to large new units, coupled with the aging of utility generating units (18 years old on average), the reliability of electricity supplies in the 1990s has been questioned. Again according to NERC, "By the mid-1990s electric generating capacity margins will be near minimum acceptable levels in some parts of the United States, even if electricity demand grows no faster than 2.2 percent per year." They state further that without changes, "the specter of unreliable electric service may become a reality."[6]

Electric utilities are in a precarious position. The construction of large baseload units can wreak financial havoc on ratepayers and/or stockholders, but to be caught short on capacity is equally unacceptable. One obvious solution is movement towards smaller units--either utility owned combined cycle powerplants or external cogenerators--which offer shorter lead times, lower capital costs and greater flexibility. Cogenerated power can be brought on line quickly--18 to 24 months for large projects, versus 8 to 10 years for coal-fired units--in an endless array of capacity configurations. If the demand outlook changes two years down the road, capacity alteration can be made quickly and efficiently.

Cogeneration is the most viable option for utilities seeking to reduce lead times and capital commitments while enhancing flexibility. Similar benefits are available to utilities through utility owned and operated combined cycle powerplants. However, this option is hampered--if not blocked outright-- by the restrictions of the outdated Fuel Use Act which prohibits the use of natural gas in large new powerplants. Utilites could compete effectively with cogenerators via combined cycle units to the benefit of ratepayers, but not without FUA repeal.

Environmental Considerations

Cogeneration systems are inherently efficient relative to conventional power production technologies, irrespective of the cogenerator's fuel source. Cogeneration can also offer environmental advantages, although the magnitude of this potential benefit depends on the fuel and technology used (and offset). According to the Office of Technology Assessment,[7] a gas turbine cogeneration system would emit less than 1 percent of the sulfur oxides, 27 percent of the particulates, and 50 percent of the nitrogen oxides relative to the combination of a comparably sized coal-fired electric powerplant (with pollution control equipment) and an oil-fired boiler producing steam. The environmental potential of gas-fired cogeneration should not be overlooked, especially at a time in which the Congress is struggling with alternatives to significantly reduce sulfur dioxide, nitrogen oxides, and other air pollutant emissions--the bulk of which are attributable to large coal-fired facilities. In addition, the gas-fired cogenerator does not have the ancillary environmental problems associated with other control strategies, e.g., sludge from scrubbers and fly ash from electrostatic precipitators which are required on new coal units.

Employment and Economic Factors

The leading U.S. industries in terms of cogeneration development include pulp and paper, oil refining, chemicals, textiles and foods. These major industries pursue cogeneration for one primary reason--it reduces their overall energy expenditures, thereby enhancing their competitive position both nationally and internationally. The results of lower production costs in a competitive environment are lower consumer prices, greater product demand and increased output and employment. Increasingly, the nation's growing service sector is also turning toward the use of cogeneration. Hospitals, hotels, colleges, nursing homes, and banking institutions all have been pursuing cogeneration to help reduce the cost of their essential services while also providing enhanced electric supply reliability.

A related policy consideration is the impact of cogeneration on oil and gas employment. Outdated demand restrictions on the use of oil and gas, coupled with increased conservation and falling energy prices, have caused a depression in the oil and gas extraction industries. Employment in oil and gas extraction has plummeted by over 200,000 workers since 1982, and the loss is expected to total 300,000 by year-end 1986.[8] Thus, about 50,000 more workers will have lost their jobs in oil and gas extraction from 1982 through 1986 than were employed in coal mining in the peak mining year since the early 1950s. Just as mining employment has been a major consideration in the acid rain debate, so too should the fate of oil and gas employees be considered when cogeneration policy is discussed. Cogeneration is the most successful new market of the gas industry, helping to offset the declines in demand attributable to conservation, industrial dislocation, and legislative impediments (FUA) to large volume industrial and electric utility gas sales.

Section 210 of PURPA Should Not Be Amended

We agree with most other parties who have testified before this committee--including electric utilities and their trade association--that there is no need to modify

PURPA through legislative action, although some regulatory adjustments may be warranted. The statutory goals of PURPA are largely being met, and regulatory modifications can be used for fine tuning. For example, the avoided cost principle is sound, although implementation of a poorly formulated avoided cost mechanism can cause major problems. Accordingly, FERC should provide individual states with guidelines and oversight guidance, but that the final decisions should remain at the state level to the extent permitted by PURPA. We further suggest that FERC initiate a study gathering data with respect to avoided costs and buyback rates, as there is no central clearinghouse for this critcal information. Regulators cannot make well-reasoned decisions based on incomplete data.

Another area where FERC should provide clear guidance to the states is on standby charges. PURPA requires electric utilities to provide backup service to qualifying facilities, but excessive standby charges can serve to block the legislative intent. Utilities argue, rightfully, that they ought to be compensated for providing standby power. Cogenerators agree and, in fact, welcome the opportunity to work out flexible maintenance schedules designed to serve the interests of cogenerators and their serving utilities. Cogenerators can be a dependable ally to utilities. According to the Office of Technology Assessment, the average annual availability of many types of cogeneration systems ranges from 90 to 95 percent,[9] versus 75 to 80 percent for new coal-fired electric utility powerplants.[10]

If standby charges are excessive, the cogenerator cannot afford to pay them and keep his project profitable. In this case the cogenerator faces an unpalatable option: disconnecting from the grid and providing redundant facilities to achieve power generation security. This is contrary to one of the primary purposes of PURPA, which was to eliminate the need for redundant equipment by allowing the cogenerator to operate parallel with electric utilities. Reliance upon an insecure power source will be deemed an unacceptable risk for most businesses. In almost all cases, the onsite cogenerator is primarily engaged in another line of business, and not the generation of electricity. If the economics of building redundant facilities do not warrant construction, the business will not opt for cogeneration.

Gas Supply and Price Considerations

The two major changes in the U.S. energy outlook that have occurred over the last ten years have been the dramatic improvement in natural gas supplies and the significant recent decline in crude oil prices. The gas supply change, as well as the falling crude price, are already affecting the gas price outlook. What these changes have not significantly affected yet is national energy policy and private and public sector planning efforts which remain mired in the dual falacies of ever rising prices and a finite resource mentality.

There have been three eras of the modern natural gas industry: (a) The 1954-73 period, an era of price controls, declining supplies, rapidly increasing demand, and a lack of competition. (2) The 1973-83 period, an era of price catch-up, falling demand, increasing supplies (especially after passage of the Natural Gas Policy Act of 1978), and decreasing market share; and (3) The modern era, a period dominated by competition, stable to declining prices, eventual supply/demand balance (the gas bubble will disppear), and increasing market share. These eras were defined by significant regulatory and structural change in the gas industry.

The regulatory philosophy of the 1954-1977 period created a situation in 1978 in which natural gas prices were well below market clearing levels in the interstate market. The rapid increase in wellhead natural gas prices that followed between 1978 and 1982 was in effect a "catch-up" to allow wellhead prices to reach market clearing prices. This "catch-up" period is now over--with natural gas prices likely to decline over the rest of this decade and be stable (relative to inflation) for the rest of this century.

Excessively low regulated wellhead gas prices created shortages as well as a price catch-up period. The gas supply problems in the interstate market during the 1970s were the product of wellhead price controls, and had nothing to do with the domestic gas resource base. The complete turnaround in the gas supply situation after passage of the NGPA provides definitive proof on the adequacy of the gas resource base--gas-fired cogeneration will in no way jeopardize the resource base as shown below.

The nation has discovered--and has available to be produced--163 Tcf of proven reserves in the lower 48 states. The Potential Gas Committee--the industry group that evaluates gas resources--has estimated that, with currently foreseeable technology and economics, there are 647 Tcf of potential gas resources which are still awaiting discovery in the lower 48 states. These potential resources are categorized as 24% probable, 37% possible and 39% speculative. This estimate of potential resources is in addition to the 163 Tcf of proved reserves. Therefore, total estimated conventional gas resources total 810 Tcf--or the equivalent of 47 years of supply at the 1984 level of gas consumption. This 810 Tcf is referred to as "remaining recoverable resources." The perception that the nation is using up this conventional recoverable resource base is the principal rationale for projections that gas production will steadily decline and that this decline will in turn force higher gas prices. This pivotal perception is mistaken because it considers the calculation of the gas resource base as a static--rather than a dynamic--assessment.

History has proven that that gas resource base is indeed dynamic, changing radically with technology development. Recent gas exploration and production activities, as well as activities that are in progress today, are opening up new horizons that will eventually add significantly to the resource base.

Total gas resources in-place in the U.S. are potentially several thousand times our current consumption level; indeed, it is within the realm of possibiity that natural gas could turn out to be our country's largest energy resource base.

A.G.A. has forecast that the excess short-term production capability ("gas bubble") will last at least another two years and possibly for the rest of the decade. Our view is reinforced by the change in Canadian Government pricing policy for gas exports; a policy which is making more gas available to U.S. energy consumers at prices that the market place will accept.

We estimate that the domestic gas "bubble" will be about 3.6 Tcf in 1985 and 2.6 in 1986. After the continuing surplus has ended, we expect that gas supply and demand will be in balance--gas-fired cogeneration will play a role in that balance. That is, there will not be a gas shortage (and, as a direct result, there will not be the significant upward pressure on wellhead prices that some analysts have forecast).

When examining short-term natural gas availability, it should be borne in mind that we currently have about 21.8 Tcf of gas available to U.S. markets. This includes a significant quantity of unused Canadian gas that is currently under contract but not being taken. This level of gas deliverability will not be quickly dissipated by rising demand or by the current relative slowdown in gas well completions. The evidence available to us indicates that U.S. peak gas deliverability remained nearly constant between 1981-1985--even though gas well completions declined during this period.

Conclusion

The primary objectives of PURPA were well-conceived, and these objectives are being met. Cogeneration offers a variety of benefits to electric ratepayers, industrial and commercial firms, electric utilities, and the nation. The natural gas industry is moving into an era of deregulation, fully able to assist the cogeneration industry in realizing its full potential. Although some regulatory adjustments with respect to cogeneration may be warranted, this is to be expected given the complexity and relative infancy of the regulations. Howwever, there is no need to amend Section 210 of PURPA.

Footnotes

1. Bruce B. McDowell, American Gas Association, "Natural Gas Use in Cogeneration Systems," Public Utilities Fortnightly, (Arlington, VA: June 12, 1986) pp. 64-66.

2. Lawrence R. Anderson, Director Office of Electric Power Regulation, FERC, Statement submitted to the Senate Committee on Energy and Natural Resources, (Washington, DC: June 5, 1986) p.7.

3. Hagler, Bailly & Company, Potential Detrimental Effects of Cogeneratin Development on Utility Costs: A Preliminary Assessment, (Washington, DC: February 1986).

4. Pfeffer, Lindsay & Associates, Inc. for the U.S. Department of Energy, Emerging Policy Issues In Purpa Implementation (Washington, DC: December 1985) p. 5.37.

5. North American Electric Reliability Council, 1985 Reliability Review, (Princeton, NJ: 1985) pp. 4-5.

6. Ibid, p. 2.

7. U.S. Office of Technology Assessment, Industrial and Commercial Cogeneration, (Washington, DC: February 1983) pp. 286-287.

8. American Gas Association, "Energy Policies and Employment in Oil and Gas Extraction versus Coal Mining," (Arlington, VA: May 23, 1986).

9. Office of Technology Assessment, Op.Cit., pp. 120-121.

10. Electric Power Research Institute, Technical Assessment Guides, (Palo Alto, CA: May 1982) p. B-55.

MAY 29 '86

CALIFORNIA
COGENERATION
COUNCIL

SUITE 2500
ONE POST STREET
SAN FRANCISCO
CALIFORNIA 94104

An Industrial
Group of
Operating
Cogenerators

May 28, 1986

Honorable James A. McClure
United States Senate
Washington, D.C. 20510

Dear Senator McClure:

The members of the California Cogeneration Council represent positive evidence of what has been achieved as a result of the Public Utility Regulatory Policies Act of 1978. It is our sincere expectation of the upcoming Senate hearing that a reconfirmation, and therefore a strengthening of the intent of PURPA will prevail.

The California Cogeneration Council membership includes:

Catalyst Energy Development Corporation
Container Corporation of America
Crown Zellerbach Corporation
Dow Chemical
Federal Paper Board Company
Garden State Paper Company
Procter and Gamble
Simpson Paper Company
University Energy

The combined gross electrical generating capacity totals 460 megawatts and the net power deliverable into the utility grid is 316 megawatts. Because each member of the CCC operates gas fired turbines with waste heat recovery systems, the overall thermal recovery exceeds 60% compared to the normal 30-35% of the utility steam generators. The nearly double efficiency in the use of a domestic fossil fuel and the concurrent avoidance by the utility is an example of the conservation possible through PURPA rules.

Not only have these facilities demonstrated a remarkably high reliability but the entire capacity was brought on line at no risk to the rate payers and at no risk to the utility shareholders.

We do recognize the continued reluctance by many utilities to accept the merits of resources developed under PURPA and the California OIR 2 program. As a means of identifying the overreactive response of the California utilities to the perceived "threat" of the independent power producers, the

California Cogeneration Council has sponsored a white paper which describes our concerns. I am pleased to attach a copy for your information.

A fair and thorough review of the short but dynamic history of the implementation of PURPA will serve to reinforce the wisdom of the 1978 legislative action. A re-affirmation of the spirit of the Act will help relieve the mounting pressure from the franchised utilities and should foster an era of cooperation, not competition, as the nation seeks to complete the grand experiment in developing alternate energy resources.

Respectfully yours,

Wayne Meek
Wayne L. Meek
Chairman

cc: Honorable Pete Wilson
Honorable Alan Cranston
Honorable Bob Packwood
Honorable Slade Gorton
Honorable Arlen Specter
Honorable John Glenn
Honorable Donald W. Riegle, Jr.
Honorable Carl Levin

Letters sent to all Committee Members.

WHITE PAPER

COGENERATION IN CALIFORNIA:

RATEPAYER BENEFITS
&
REGULATORY BARRIERS

Prepared by the

CALIFORNIA COGENERATION COUNCIL

May 1986

EXECUTIVE SUMMARY

Both the California Legislature and the California Public Utilities Commission (CPUC) have consistently determined that cogeneration produces significant benefits for California ratepayers. These include increased efficiency, avoidance of expensive new baseload plants, and increased diversification and planning flexibility.

Development of cogeneration projects by non-utility companies substantially reduces the risks to ratepayers. For example, when utilities develop plants, ratepayers are exposed to risks such as cost overruns, cost of cancelled plants, excess maintenance cost to achieve specified performance levels and costs to retrofit safety and environmental controls. In the 1980s and 1990s, California ratepayers will pay billions of dollars in higher rates to cover these risks for utility built plants. Non-utility companies that develop cogeneration plants absorb all of these risks.

To capture these benefits for ratepayers, the legislature and CPUC have eliminated many barriers to non-utility cogeneration. In response, many of California's leading industrial companies have invested hundreds of millions of dollars in new cogeneration projects. Effective management of these projects requires stable regulatory policies and orderly procedures.

In the past year, a number of actions by electric utilities and the CPUC have threatened the viability of these projects. Many have been raised in abbreviated proceedings; action has sometimes been based on inadequate facts or inaccurate data.

Procedural issues have themselves become a barrier to cogeneration. These issues include a proliferation of proceedings, lack of clarity among forums, repetition of issues, delay, and inconsistent decisions.

Cogenerators do not seek special treatment. The companies in the California Cogeneration Council are committed to absorb the risks and rewards of changes in market conditions. They do not seek to pass these risks onto the ratepayers. However, they cannot absorb the regulatory risk that has arisen.

Cogenerators ask that a number of key policies be firmly established and not be reviewed except on a regularly scheduled and relatively infrequent basis. These policies should be designed to promote ratepayer indifference regardless of changes in market conditions.

Specific matters requiring stabilization include:

1. Firm establishment of the principle of gas rate parity for cogenerators. This is essential if the viability of cogeneration projects is to be based on their efficiency as opposed to the latest trend in rate design.
2. Establishment of a balanced market responsive mechanism to set avoided energy prices. Existing mechanisms are too rigid and so-called "real time pricing" proposals are not verifiable or administrable.
3. Recognition of the value of efficient self-generation. Self generation increases the efficiency of California industry, provides needed diversification for our utilities, and protects the ratepayers from major risks. Properly sized cogeneration projects should not be subject to attack as "PURPA machines" or "uneconomic by-pass" and policies should recognize the value of these projects to the ratepayers.
4. A determination as to whether a mechanism to adjust capacity payments is appropriate. If so, a realistic and equitable mechanism should be adopted.
5. A recognition that the cost of providing stand-by power is less if a utility has more than adequate capacity. Staff and utilities should be directed not to propose higher stand-by payments if they also contend that there is surplus capacity.

The members of the California Cogeneration Council express their desire and willingness to work with the utilities and the Commission to resolve these matters in a way which is fair to both the ratepayers and cogenerators.

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COGENERATION PRODUCES SIGNIFICANT BENEFITS FOR CALIFORNIA RATEPAYERS

Both the California Legislature and the California Public Utilities Commission (CPUC) have consistently determined that cogeneration produces significant benefits for California ratepayers.

Specifically, cogeneration:

1. provides fuel efficiency in the production of electricity, steam, and heat, helping to reduce reliance on foreign fuel,
2. avoids the need to build expensive base load plants,
3. contributes to the diversification of utility systems, and
4. provides flexibility in planning for system needs including reduced lead time.

In addition, development of cogeneration projects by non-utility companies substantially reduces the risks to which ratepayers would otherwise be exposed if utilities were to develop the projects. The ratepayer risks absorbed by cogenerators include:

1. Exposure to costs of plant held for future use.
2. Exposure to costs of permitting projects which do not receive all necessary permits and do not proceed to construction.
3. Exposure to costs of plants partially completed and then canceled or mothballed.
4. Exposure to cost overruns on plants not completed within budget.
5. Exposure to higher operating costs and interest during construction caused by failure to complete projects on time.
6. Exposure to costs of failure to meet performance expectations for a plant.
7. Exposure to costs of plants in rate base which do not operate over extended periods of time.

8. Exposure to excessive maintenance costs to keep plants operating at acceptable levels.

9. Exposure to excessive recovery of capital for plants retired prematurely.

10. Exposure to costs of air or water pollution retrofits.

11. Exposure to toxic or nuclear waste disposal costs.

12. Exposure to nuclear decommissioning costs.

13. Increase expected in returns on stocks of utilities with large construction programs.

CALIFORNIA HAS CLEAR POLICIES TO CAPTURE THESE BENEFITS BY REMOVING BARRIERS TO COGENERATION DEVELOPMENT

Legislative enactments and CPUC decisions have established a number of measures intended to eliminate barriers to the development of cogeneration projects in order to capture these benefits for the ratepayers. Examples include:

1. California Public Utilities Code Section 454.4 provides that gas fuel for cogeneration projects shall not be priced higher than the price of fuel for utility electric generation (UEG).

2. California Public Utilities Code Section 454.7 provides for priority protection from curtailment for cogeneration gas fuel.

3. CPUC Decision 85-04-072 assures that cogenerators will have to pay no more for gas used to produce process steam than they would have paid in the absence of the cogeneration project.

In addition, the CPUC has on two occasions penalized California electric utilities for not being sufficiently responsive to these policies to encourage cogeneration.

MAJOR INVESTMENTS HAVE BEEN MADE IN COGENERATION PROJECTS

Responding to these clear policies, many of California's leading industrial companies have invested hundreds of millions of dollars in new cogeneration projects. By definition, all of these projects must be more efficient than the utilities.

A BARRAGE OF UTILITY AND CPUC ACTIONS NOW THREATENS THE ECONOMIC VIABILITY OF MANY OF THESE PROJECTS

In the past year, a number of actions by the electric utilities and the CPUC have undermined the clear policies in place. The frequency of these actions has reached a fever pitch in the first four months of 1986. These actions threaten the economic viability of cogeneration projects. Effective management and operation of these projects requires stable regulatory policies and orderly procedures. Constant attacks on cogeneration do a disservice to the Commission and the ratepayers.

THE THREATENING ACTIONS ARE WITHOUT FOUNDATION IN FACT OR POLICY

The recent actions threatening cogeneration projects have come about in the absence of any change in policy at either the Legislature or the CPUC. There have been no changes in the legislative or CPUC findings as to the benefits of cogeneration to the ratepayers. Most significantly, many of the actions and proposed actions of the utilities and CPUC staff have been cast in the context of emergencies. This has led to action being taken on the basis of inadequate factual records which in many cases contain demonstrably inaccurate information.

LET THE MARKETPLACE OPERATE

Cogenerators do not seek special treatment. The companies in the Cogeneration Council are committed to absorb the risks and rewards of changes in market conditions. They do not seek to pass these risks onto the ratepayers. However, these companies cannot absorb the degree of regulatory risk that has arisen.

STABILIZE UNDERLYING POLICIES

Cogenerators ask that a number of key policy premises be firmly established and not be reviewed except on a regularly scheduled and relatively infrequent basis. These policies should be designed to promote ratepayer indifference regardless of changes in market conditions. In this way, the constant pressure to change policies and practices can be avoided even if the market remains volatile.

SPECIFIC POLICIES REQUIRING STABILIZATION

Parity of Gas Rates

Cogenerators have consistently sought parity in their gas rates so that they stand or fall on the basis of their efficiency as compared to that of the utilities. While the Commission has generally acknowledged the importance of parity, recently a variety of novel proposals to undercut the parity concept have been made by the utilities and the staff. Again, cogenerators are asking that this issue be addressed with finality in the pending gas rate design proceedings.

Gas rate parity has two components. The price for gas should be no greater than the customer would have paid in the absence of the cogeneration system. Otherwise, the cogenerator runs the risk of being penalized with higher fuel costs merely because of the cogeneration system.

Similarly, cogenerators should not be asked to pay more for gas than the rate the electric utility is charged and which is used to calculate avoided energy costs. The cogenerator is required to be more efficient than the utility. Removing this linkage of gas costs between the utility and the cogenerator allows discretionary rate design to swamp the value of efficiency.

Adopt a Market Responsive Price Mechanism

In every rate case there are extensive debates on what assumptions to use in the calculation of the Incremental Energy Rates (IERs) on which avoided energy costs are based. By the time the IERs are adopted in the rate case, all parties acclaim that they are incorrect. Some say they are too high while others claim they are too low. As each month goes by after the adoption of IERs, the basic premises on which they were calculated become more eroded and new claims of inaccuracy arise on both sides.

The Commission should adopt a price mechanism that is responsive to market conditions and not to periodic debates in Commission hearings. The several key factors that cause IERs to move significantly should be identified and prices updated on a regular basis consistent with actual data on these factors.

Recognize the Value of Efficient Self Generation

Substantial alarm has been generated by the electric utilities and Commission staff members regarding the emergence of the so-called "PURPA machine." Simply stated, this is a rubric for a cogeneration facility that is not sized to match either the thermal or electrical loads of the site and is simply a non-utility power plant which meets minimum FERC steam efficiency requirements. The Commission reacted to these concerns by calling for the proper sizing of cogeneration projects in relation to on-site loads.

Proper sizing can relate to either the thermal loads or electrical loads of the site. However, the Commission appears to believe that a cogeneration facility which is sized to meet on-site thermal loads but which sells substantial amounts of power to the utility is still a "PURPA machine". Furthermore, for those who have sized to meet on-site electrical loads, the Commission now claims that they are engaging in something called "uneconomic bypass." In sum, it appears that regardless of how the cogeneration facility is sized, the Commission feels it is not in the best interests of the ratepayers.

Efficient self-generation promotes all of the policies established by Congress, the Legislature, and the Commission. The Commission should clearly acknowledge that cogeneration projects which are sized to meet either on-site thermal or electrical loads are properly sized and in the best interests of the ratepayers. The Commission should also direct the utilities and the staff to cease their attacks on cogenerators that meet one or both of these criteria.

Capacity Adjustment Mechanism

In at least four proceedings in four years, there have been proposals to reduce capacity payments to cogenerators on the basis of reduced need for reliability. In each case, the Commission found that the concept was intriguing and encouraged it to be raised in another proceeding. In one instance, a modified adjustment was adopted on a temporary basis.

Now the issue is raised for a fifth time in the PG&E general rate case. The burden of continuous proceedings on capacity reliability adjustments has gone beyond the limits of reasonableness. Cogenerators request that a mechanism to address this issue be determined with finality in the Standard Offer #4 proceeding or the PG&E rate case.

The Relationship Between Stand-by Rates and Capacity Adjustment Mechanisms

California electric utilities claim that they have adequate supplies of new resources and that capacity payments should be reduced. Yet in the most recent rate cases, they have sought increases in stand-by rates for cogenerators. There is a correlation between the value of capacity and the cost of providing stand-by service. As reserve margins are smaller, capacity has a higher value and the cost of providing stand-by service is also higher. The converse also holds. The relationship between these two values should be recognized and the utilities and staff should be prevented from seeking inverse movements in them simultaneously.

Adopt Consistent Policy on the Need for Dispatch Flexibility

The electric utilities and the staff have recently promoted the need for increased dispatch flexibility for cogenerators. Cogenerators have not resisted this concept in principal but no specific proposals have been put forth for evaluation by either the utilities or the staff. At the same time, in the pending PG&E rate case, the utility seeks to reduce the number of time periods in a day during which rates are adjusted. This reduces the opportunity for dispatch flexibility by reducing rather

This reduces the opportunity for dispatch flexibility by reducing rather than increasing the number of time periods in which output adjustments can be made with an economic effect. The Commission should direct PG&E to promote either increased dispatch flexibility or reduced flexibility but to not do both simultaneously.

PROCEDURAL CONFUSION HAS BECOME A MAJOR BARRIER TO SOUND POLICY

Procedural issues themselves have become a primary barrier to sound policy. These issues include a proliferation of proceedings, lack of clarity among forums, indecisiveness, delay, repetition of issues, and inconsistent decisions.

1. Proliferation of Proceedings

Major issues affecting gas cogenerators can arise in as many as 10 or 15 proceedings a year. These include all general rate cases, ECACs, GACs, CAMs, many OIIs, and special proceedings like OIR-2.

Basic self defense requires that all of these proceedings be monitored. Often, major interventions become necessary. Both the cost and quantity of non-productive effort that goes into the process are demoralizing.

2. Lack of Clarity Among Forums

Because issues can arise in almost any proceeding, cogenerators are in constant jeopardy. A cogenerator planning to raise an issue in one proceeding can find that it has already been dealt with in another proceeding in which the cogenerator had not participated. Issues often shift from proceeding to proceeding thereby preventing any rational budgeting and planning for significant interventions.

3. Indecisiveness

Cogenerators have made major investments in proceedings in which specific issues have been designated for significant consideration. Many times, the response of the Commission has been to ignore this effort and not make any decision. In other cases, an issue designated for major review has been changed in mid-proceeding.

4. Delay

There is more than one case in which Commission decisions on major issues affecting cogenerators have been delayed for 6 months or more. In one case, this was caused by assigning the same Administrative Law Judge to two major proceedings simultaneously, the Edison General Rate Case and the Long Run Standard

Offer proceeding. This made it virtually impossible for serious attention to be given to one.

5. **Repetition of Issues**

On more than one occasion, the Commission staff has made proposals which have not been well developed. In some cases, the proposals have clearly exceeded statutory limitations. Even though the Commission may dismiss such a position of the staff, there seems to be no constraint on the staff raising the issue in subsequent proceedings. Once raised, an issue must be addressed, even if it appears to be frivolous or without merit.

6. **Rate-Making by Advice Letter**

A long established procedure of the Commission allows the non-controversial adjustment of tariffs by means of a cursory Advice Letter filing. Recently, the utilities, apparently with Commission encouragement, have begun to propose major and highly controversial rates in Advice Letters. The narrow and cursory nature of these proceedings constrains any serious consideration of broad policy issues. The Advice Letters must be protested with the result that they are often moved into other proceedings for consideration. There are serious notice problems when important matters are decided by Advice Letters.

MULTIPLE PROCEEDINGS ARE MORE COSTLY TO COGENERATORS THAN TO OTHERS

In proceedings addressing issues affecting cogenerators, the Staff, the utilities, and residential ratepayers are all able to recover their costs from the ratepayers. Cogenerators must absorb all of their own costs of counsel and experts and thus carry a unique burden from the plethora of proceedings. We would like to explore with the Commission options to place cogenerators on a level playing field procedurally.

PROCEDURAL STABILITY IS NECESSARY FOR A SOUND BUSINESS ENVIRONMENT

Cogenerators recognize that the Commission must manage a demanding agenda and that the times are turbulent. We believe that the interests of the Commission and cogenerators can both be served by stabilizing certain fundamental policies and the procedures in which to consider policy changes.

This White Paper addresses a number of policies that can and should be stabilized. The California Cogeneration Council expresses its willingness to work with the Commission to this end and to develop orderly procedures that can minimize the cost and potential confusion of policy change.

TESTIMONY

OF

CHADBOURNE & PARKE

ON

IMPLEMENTATION OF THE PUBLIC UTILITY REGULATORY POLICIES ACT

Before the
Committee on Energy and Natural Resources
of the United States Senate

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I. INTRODUCTION

Chadbourne & Parke is pleased to submit this testimony on implementation of the Public Utility Regulatory Policies Act (PURPA) for inclusion in the record of the hearings of the Committee on Energy and Natural Resources of the United States Senate. The testimony is filed on behalf of the firm, not on behalf of any of its clients.

The debate over PURPA, its implementation and whether in 1986 it is a valid instrument of public policy, raises issues that fall into two broad categories: (1) issues that touch on the efficiency and fairness of the relationship established by PURPA between qualifying cogeneration and small power production facilities (QFs), utilities, and ratepayers, and (2) issues regarding the availability of PURPA benefits based on fuel use, operating and efficiency standards, facility size, and type of ownership. */ This testimony is designed to shed light on these issues by presenting the firm's perspective, gained by representing QFs in all parts of the nation within the PURPA framework.

A. Background

Chadbourne & Parke is a law firm with offices in New York City and Washington, D.C. The firm has an extensive

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*/ Qualifying cogeneration and small power production facilities are defined by FERC's rules, 18 C.F.R. §§ 292.201-207. These rules contain certain minimum efficiency, fuel use, operating, ownership and size criteria.

energy law practice, of which a substantial component is representation of QFs in all aspects of their development, including arrangement of their financing, negotiation of power sales agreements with electric utilities, steam sales agreements, construction agreements, and appearances on behalf of QFs before federal and state regulatory bodies. The firm has represented both cogenerators and small power producers, that use solid, liquid and gaseous fuels in their facilities. The total nameplate capacity of QFs with which the firm has or has had representational association is about 3000 megawatts. The firm has worked with QFs in approximately 25 states, in all regions of the country.

The firm welcomes Congressional review of the implementation of PURPA and respects the Committee's desire to review PURPA in light of the changes in energy markets and in other conditions in the seven and one-half years since its enactment.

B. Summary of Chadbourne & Parke's Position on PURPA

1. Given that major utility challenges to PURPA were not successfully resolved until 1983, */ and that the

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*/ See FERC v. Mississippi, 456 U.S. 762 (1982) (upholding the facial constitutionality of §§ 201 and 210 of PURPA); American Paper Institute, Inc. v. American Electric Power Service Corp., 461 U.S. 402 (1983) (unanimously overturning a Court of Appeals decision striking down the full-avoided-cost and interconnection rules). (Chadbourne & Parke represented the American Paper Institute, Inc. in both cases.)

environment is still not favorable to QF development in much of the country (the Southeast, the Middle Southern states, TVA's service territory, the Midwest and Great Lakes areas, and the Pacific Northwest) due to utility overcapacity and low fuel costs, PURPA has been remarkably successful overall in encouraging investment in electric generating capacity that is economically efficient, environmentally preferable, and equitable to ratepayers. However, the program is still in its infancy and its success in meeting these objectives, over the long run, is not yet assured.

2. Some PURPA implementation problems have been encountered, but this is to be expected given the complexity of the statute, the difficulty of predicting the path of fuel prices and the rate of growth in demand for electricity, the differences in initial state approaches to implementation, and the marked changes in behavior of electric utilities required by PURPA.

3. Most states seem to be getting a handle on PURPA as they gain experience in its implementation. Thus, problems of implementation have begun to be resolved at the local level. The trend of more effective state regulation should continue over time.

4. In evaluating PURPA, the firm believes that it is important to keep in mind the larger context in which PURPA issues should be considered:

a. Many utilities presently have surplus capacity above reserve margins. However, virtually every responsible journal of the electric utility industry, as well as DOE, warns of the need for new construction to meet foreseeable needs for generation capacity in most regions. Most of these publications cite fear of regulatory risk as the major inhibitor of new utility capital spending programs. QF capacity can play a significant role in meeting the need for new capacity on a least-cost basis, and in a manner that will mitigate regulatory risk for the utility industry.

b. PURPA encourages the development of generating capacity in relatively small increments. Addition of capacity in small increments mitigates ratepayer exposure to the financial risk of cost overruns and excess capacity in an era of uncertain demand.

c. PURPA is providing the first real competition for utilities for the supply of electricity within their service territories. This competition can and will stimulate creative and competitive responses from the utilities and will ultimately bring significant benefits to utility ratepayers. Reduction of

PURPA benefits would be inconsistent with what we believe to be the proper policy direction of utility regulation: to promote a competitive bulk power supply market.

d. The benefits of PURPA QF development are not confined to greater efficiency in the electric industry only: industries dependent on steam and/or electricity also benefit from PURPA through reduced steam and/or electricity costs. This makes U.S. industry more competitive world-wide and often provides a much-needed stimulus to local economies by creating and preserving jobs in industries using QF technologies.

e. Many, if not all, PURPA technologies have substantially less adverse impact on the environment than conventional utility generation technologies. Indeed, some PURPA technologies are environmentally beneficial (e.g., QFs fueled by municipal and other waste).

f. The present economic and enforcement environment in which QF investment decisions are made is not promising. Congress continues to reduce tax benefits for QFs. Avoided costs continue to plunge as fuel prices decline and short-run utility generation capacity surpluses increase. And the Federal Energy Regulatory Commission (FERC) has adopted a passive approach to enforcement of its regulations implementing PURPA. These conditions suggest that QF development is in for some hard times. If PURPA were altered to erode the position QFs have managed to build, further development would be seriously jeopardized.

C. Summary of Contents

Chapter II of this testimony is designed to provide background for PURPA review. Section A is a discussion of the purposes of the PURPA program established in sections 201 and 210 of PURPA. Section B is a discussion of the effect of PURPA, in particular the avoided cost rule, on economic efficiency and equity. Section C considers the consistency of PURPA with the trend toward greater competition in the bulk power supply markets. Section D provides the context for PURPA oversight through a discussion of changes in tax policy and changes in avoided cost levels, and FERC enforcement.

Chapter III is a review of PURPA implementation with an emphasis on how the relationship established by PURPA among QFs, utilities, and ratepayers has been implemented. Section A sets out that relationship. Section B is the firm's view on how that relationship has evolved to date. Section C relates several anecdotes describing in detail the implementation of the relationship requirements in some of the actual cases in which the firm has been involved. Section D is a review of anecdotes presented in a DOE-sponsored study entitled, "Emerging Policy Issues in PURPA Implementation," by Pfeffer, Lindsay & Associates, Inc. (Dec., 1985). We offer this review because the anecdotes cited in the Pfeffer study may be misleading.

Chapter IV is the firm's response, based on our experience, to the major complaints raised by utilities and others to PURPA and the way in which it has been implemented.

Chapter V offers our conclusions.

II. BROADER CONTEXTS

This Chapter provides both the background and the broader contexts in which PURPA implementation should be examined.

A. The Purposes of PURPA

Neither PURPA nor Title II of PURPA contains express "Purposes" delineating precisely what Congress had in mind when it enacted sections 201 and 210 of Title II. The purposes of Title I cannot automatically be borrowed to construe these sections, as some have done, because Title I addresses a different subject (retail ratemaking) than Title II and sections 201 and 210. Thus, it is necessary to scrutinize the legislative history of PURPA for guidance as to what was contemplated by Congress when these sections were enacted.

While elements of PURPA were taken from differing Senate and House bills, PURPA as it was enacted is a creation of a Senate-House Conference Committee. However, the Joint Explanatory Statement of the Committee of Conference on PURPA does not contain a clear statement of purpose for the entire statute, Title II, or sections 201 and 210.

Statements by major proponents of the legislation when the Conference Report was brought to the floors of the Senate and House do provide general guidance regarding PURPA, if not precisely for Title II or sections 201 and 210. Thus, Senator Jackson, Chairman of the Senate Committee on Energy and Natural Resources, said that PURPA was aimed "at promoting conservation of electric energy by consumers, efficient use of facilities and resources by the utility industry, conservation of capital by more effective use of existing plants and equity in ratemaking." 124 Cong. Rec. 34,558 (1978). Similarly, Congressman Dingell, then Chairman of the House Subcommittee on Energy and Power, stated that PURPA "is designed to lower the need for new facilities and reduce energy consumption by making more efficient the generation and delivery of power by utilities and the consumption . . . of power by its customer [sic]." 124 Cong. Rec. 38,369 (1978). The problem with these statements is that, while they purport to explain the purposes of PURPA, they appear to repeat or restate the purposes only of Title I. Thus, the statements certainly do not reflect the intent of, for example, Title V of PURPA relating to crude oil transportation systems or Title IV, relating to small hydro systems. As such, it is not reasonable to suppose they are the only purposes of Title II, or of sections 201 and 210 in particular.

We think that the search for the definitive "Purposes" of sections 201 and 210 is therefore futile. However, the absence of statements of purpose causes no problems of statutory construction because the intent of sections 201 and 210 ismanifest on their face: to give maximum encouragement to non-utility cogeneration and small power production by overcoming impediments to their development, and at the same time, ensuring that rates to consumers are no higher than they would be otherwise.

That Congress believed impediments existed is clear. As the U.S. Supreme Court said in FERC v. Mississippi, 456 U.S. 742, 750 (1982), in upholding the constitutionality of PURPA:

> Section 210 of PURPA's Title II, . . . seeks to encourage the development of cogeneration and small power production facilities. Congress believed that increased use of these sources of energy would reduce the demand for traditional fossil fuels. But it also felt that two problems impeded the development of nontraditional generating facilities: (1) traditional electricity utilities were reluctant to purchase power from, and to sell power to, the nontraditional facilities, and (2) the regulation of these alternative energy sources by state and federal utility authorities imposed financial burdens upon the nontraditional facilities and thus discouraged their development. (citations omitted).

Thus, in order to ascertain whether PURPA implementation has been consistent with the intent of Congress in sections 201 and 210, we must ask whether implementation has given maximum encouragement to cogeneration and small power production by overcoming utility obstacles and regulatory impediments to their development without leading to rates higher than would otherwise be in place without PURPA. We think that from this perspective, PURPA has been successful. However, as is suggested by both the anecdotes we discuss in Chapter III of this testimony and utility testimony in this hearing, considerable resistance to non-utility cogeneration and small power production continues to exist. In addition, we believe that most PURPA cogeneration and small power production has come on-line or is being developed with buy-back rates that are below avoided cost, thereby providing direct and immediate ratepayer benefits.

Obviously, however, in reviewing PURPA, Congress must take a broader view than merely assessing whether its implementation is consistent with the ostensible intent of Congress in sections 201 and 210. Congress should want to know whether PURPA implementation is consistent with economic efficiency and equity -- the two major criteria on which the public policy merits of any regulatory program should be judged. And Congress should want to know whether the PURPA model is in tune with developments in the underlying economics of the electric generating industry as it moves toward a new competitive era. We discuss these issues in the next two sections.

B. Efficiency, Equity and PURPA

Much attention has been given to whether PURPA implementation has promoted economic efficiency and equity. In Chapter III of this testimony, we provide detailed information to support our conclusion that PURPA implementation has indeed promoted both economic efficiency and equity. In this section we offer background on the relationship between economic efficiency, equity and PURPA, and in particular, on the centrally important avoided cost rule implemented by PURPA.

The notion of economic efficiency is concerned with the efficient use of society's scarce resources in a manner that permits maximization of social welfare. Maximization of social welfare requires attainment of both allocative and productive efficiency. Allocative efficiency speaks to the allocation of society's scarce resources to produce goods and services most highly valued by society. Productive efficiency speaks to the use of those resources to produce goods and services in their most efficient, least-cost manner. In the electricity context, economic efficiency would be enhanced by measures that meet demand for end-users at the lowest total cost to society.

It is unlikely that Congress had this precise notion of economic efficiency in mind when it enacted PURPA. However, elements of PURPA suggest that Congress was concerned with economic efficiency in a general way and, in particular, with the attainment of a goal related to productive efficiency -- namely, engineering efficiency, which, in this context has as its objective the extraction of as much useful energy from a given fuel source as possible.

Many analysts of PURPA, in assessing its attainment of these efficiency objectives, have focused on PURPA's effect on rates. Thus, the recent DOE study authored by Pfeffer, Lindsay & Associates, Inc., supra, looked primarily at the immediate effect of PURPA on electric rates in assessing PURPA's attainment of economic efficiency. But the short-term effect on rates is only one relevant indicator of efficiency. */ Other very important aspects include: (1) the environmental impact of PURPA technologies; (2) the effect of PURPA on markets for steam produced by cogeneration units; (3) the effect on employment levels and the competitive position of U.S. and, perhaps most importantly, (4) the long-run impact of PURPA in facilitating competition in electric generation markets. A thorough review of PURPA from the perspective of economic efficiency must keep all of these effects in mind.

How does PURPA stack up against this broader definition of efficiency? Very well. The key requirement of PURPA that relates to economic efficiency is the avoided cost rule, 18 C.F.R. § 292.304. The rule requires utilities to offer to

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*/ In fact, rate reductions due to purchases from QFs at less than avoided cost would be evidence of probable realization of some economic efficiencies, but the absence of rate reductions would not indicate either way whether gains in economic efficiency had been achieved.

by QF capacity and energy at a rate equal to the costs the utility would have incurred but for the purchase from the QF.

The avoided cost rule is sound public policy because it promotes economic efficiency. Buy-back rates set at full avoided cost provide the proper incentive for construction of all QFs with costs equal to or less than the utility's full avoided cost. A buy-back rate set at less than the utility's full avoided cost would encourage less than an optimal level of QF production, because some QFs with costs less than utility avoided costs would not be able to operate profitably.

Thus, setting QF buy-back rates for all QF output at full avoided cost encourages reliance on least-cost sources of electricity, i.e., it enhances productive efficiency. The real beauty of the full avoided cost rule is that it effects a "Pareto improvement", i.e., it enhances productive efficiency without making the utility or its ratepayers worse off. The utility pays QFs only the costs it would have incurred if it had generated the electricity itself, and ratepayers pay no more for that electricity. Indeed, ratepayers often pay less, because QFs often agree to be paid a buy-back rate that is less than full avoided cost in return for concessions on other aspects of their relationship with the utility that are not required by PURPA.

PURPA also serves the other, above-mentioned aspects of economic efficiency quite well. First, with respect to small power production technologies, PURPA promotes the use of renewable resources and waste, and innovation in the use of these technologies, to produce electricity. Many, if not all, of the technologies fueled by renewable resources and waste have a lesser adverse environmental impact than traditional generating technologies.

Second, because of the productive efficiencies inherent in PURPA cogeneration technologies, these facilities provide an inexpensive source of industrial steam.

Third, the efficiencies in production of electricity and steam encouraged by PURPA bring substantial secondary benefits that multiply throughout our economy. Reduced prices of electricity and steam will reduce costs of production for U.S. industries relying on these inputs of production. These lower costs translate into a healthier U.S. economy, with its attendant benefits of an improved international competitive posture for U.S. industry and balance of payments, and increased U.S. production, development, tax-base and employment.

Perhaps the most important benefit of PURPA is its effect on facilitating the inevitable transition to competition in bulk power supply markets. We discuss this effect in greater detail in the next section.

Finally, PURPA provides all of these benefits without adversely affecting utilities or their ratepayers. As pointed out above, buy-back rates based on full avoided costs do not increase either utility costs or rates. For these reasons, when it is implemented properly, PURPA is a prototype of good public policy legislation. */

C. The Validity of PURPA in 1986 From the Perspective of Trends in Electric Generation Markets

We suggest that electric generation markets in 1986 are characterized by the following conditions:

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*/ Avoided-cost pricing is not, however, perfect from an economic efficiency perspective. For one thing, it cannot account for "externalities" in production, *i.e.*, that indirect effects of production often cause costs or benefits which are not incorporated into the pricing mechanism. For example, a cogeneration facility fueled by refuse is paid the utility's avoided cost of production. However, such a facility provides an "external economy" to the community that would have been responsible for disposing of that refuse. In such a situation, to "internalize" the externality, and provide the developer of that QF (and others like it) with an incentive to develop that fully reflects the social benefit the QF provides, the buy-back rate should be set at the utility's full avoided cost plus an amount that reflects the social benefit of disposing of the community's refuse (*e.g.*, perhaps the cost of operating a landfill plus an amount reflecting social savings from not having polluted the environment with a landfill). By establishing the full-avoided-cost ceiling on buy-back rates, Congress essentially provided that QFs should supply external benefits without compensation through utility rates.

The tax incentives offered to QF development in effect represent an attempt by Congress to approximate the external economies of QF development. But upon repeal of those tax benefits, see *infra* at 21-22, the avoided cost methodology will underestimate the actual social benefit of much QF development.

1. The existence of present surpluses of generation capacity beyond those needed to serve load and meet prudent reserve margin requirements in certain regions.

2. Pervasive uncertainty as to whether the supply of generation capacity will be sufficient to meet loads cost-effectively in the U.S. in the 1990s, absent the construction of additional generation capacity.

3. Very long lead times associated with large utility-constructed baseload powerplants -- indeed, such long lead times that it may not be possible to construct such plants in sufficient time to meet new loads cost-effectively in the 1990s.

4. Loss of economies of scale associated with conventional utility generation units.

5. Deregulated prices of oil and incrementally deregulated prices of gas.

6. An expanding number of entities capable of constructing their own small-sized baseload power generation facilities, usually in less than half the time that it takes utilities to construct large powerplants.

7. A widening spectrum of investors and lenders from which capital may be raised for small- and medium-sized energy projects.

8. An electric utility industry that has been financially burned by its experience in trying to build, and

have ratepayers pay for, large baseload powerplants that, for many reasons, generally turned out to be much more costly than had been expected.

9. Improved computer, transmission, and other equipment facilitating the entrance of small power generators into utility markets.

10. The success of PURPA in bringing on line several thousand megawatts of new generation capacity, with much more under contract, at a price that compares favorably with recent utility additions to capacity.

To us, these conditions suggest that there will soon be a need for additional electric generating capacity and that PURPA QFs can play a significant role in meeting this need cost-effectively. In this environment, it is important that neither the Congress nor the FERC take steps that would reduce the contribution that QFs can make to meet capacity requirements on a cost-effective basis.

The conditions outlined above also suggest a cost environment in which the traditionally-assumed natural monopoly characteristics of electricity generation are disappearing. They suggest that economies of coordination within vertically integrated utilities may not outweigh the benefits of open competition among unaffiliated electric generators. Thus, these conditions suggest that we are moving towards an electric utility services environment in which the regulation of power generation may no longer be necessary or desirable.

It is our opinion that deregulation of the generation of electricity in the United States could, if carried out carefully over time, bring substantial benefits to the economy in the form of lower rates for power and an ability to use fewer of our scarce resources to meet the demand for electric energy services. However, the benefits will not occur absent strong competition among electric generators of all kinds. At the moment, the success of PURPA in encouraging considerable new generating capacity in the short time in which it has been in effect suggests that adequate competition could exist to sustain competitive, deregulated bulk power markets in at least some regions of the country. However, across-the-board deregulation of electric generation is not a prudent policy today. There remain too many unanswered questions about the implications of deregulation, and especially about appropriate access to the nation's electric transmission system.

Thus, we see the country as being in a long transitional period between the days of declining utility marginal costs of generation, and cost-of-service regulation that was easy to justify because of clear economies of scale -- a period which began to end in the early 1970s -- and another, different era, characterized by extensive bulk power supply competition and deregulation of bulk power supplies.

In this transitional era, the greatest significance of PURPA may be its ability to telescope the coming era through its encouragement of competition and to enable collection of evidence regarding the extent and the actual workings of competition in the bulk power market. We believe that these benefits of PURPA are critically important and urge that Congress and the FERC be mindful of them when contemplating whether changes should be made in PURPA or its implementing regulations. In fact, we believe that any changes to PURPA should be scrutinized from the perspective of whether they would encourage competition in bulk power supply markets and/or whether they will help the country assess the desirability of deregulated bulk power markets.

In this regard, we are aware that some believe that PURPA is not a good test of the strength of competition in bulk power markets or the desirability of deregulation of bulk power supply. Thus, it is argued that open competition would not provide a guaranteed market for QF electricity or a guaranteed offer to pay for that output at avoided cost rate levels. We agree. However, a fully competitive market would also be characterized not by monopsony, but rather by open competition among distribution utilities to buy QF power. Neither of these aspects of a fully competitive market now exists, as utilities maintain strict control over access to their transmission systems. Under these conditions, the buy-back and avoided cost requirements of PURPA are necessary to encourage efficient competition and, as such, come as close as possible to simulating competitive market conditions within the existing industry structure and conduct. */

D. What Else Is Happening to QFs?

The final element of the big picture in which we hope the Committee will review PURPA is provided by the tax, avoided cost, and FERC enforcement climate. Developments in all three areas present danger signals to QF investors.

Starting in 1978 with the Energy Tax Act and ending in 1981 with the Economic Recovery Tax Act, Congress conferred benefits on American industry generally, and particularly on certain energy-producing technologies, that were favorable to QF development. Thus, Congress legislated a ten percent investment tax credit for investment in QF equipment. Congress also provided for energy tax credits equal to ten to fifteen percent of the cost of some QF equipment. In addition, 95 percent of the investment in most QF equipment could be depreciated over five years. Finally, Congress granted investors in some kinds

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*/ Even under deregulation, we fully expect that long-term purchase agreements will be necessary for financing the construction of most generating units, whether QFs or not.

of QFs access to the municipal bond market and its tax-exempt interest rates. These provisions encouraged investment in QFs.

However, in 1982, Congress began to change direction by scaling back these benefits. The tax credit for investment in cogeneration expired at the end of 1982. Energy tax credits for other QF equipment expired at the end of 1985 (although pending tax legislation would extend a few of these credits for certain projects for another two or three years). Also, since 1982, Congress has restricted access to municipal bond markets for investors in private facilities including most QFs.

Pending tax legislation would repeal the 10 percent investment tax credit for property placed in service after December 31, 1985. It would also stretch out QF depreciation periods from five to fifteen to twenty-five years. Utilities, too, will experience a decrease in tax benefits, but this increase in utility costs is unlikely to be fully and quickly reflected in state avoided cost calculations. Thus, the effect of these pending provisions on investment in QFs -- amounting to an approximately 50 percent increase in the after-tax cost of investing in QFs -- will undoubtedly reduce investment in PURPA technologies.

A second danger signal for QFs at present is falling avoided costs. Lower utility fuel prices and a general capacity surplus that has endured longer than many thought likely have caused avoided costs to decline precipitously. While we believe that avoided costs will begin to increase again over time, their present low level has also had the effect of discouraging investment in QFs which, as we argue above, can play a critical role in meeting loads in the 1990s.

A third concern is the FERC. Vigorous implementation of its rulemaking responsibilities under PURPA was a hallmark of early PURPA implementation. FERC's responsibilities have shifted over the years to one of monitoring and enforcement of the PURPA program. In carrying out its enforcement responsibilities, however, FERC has been less than vigorous.

Two FERC decisions in particular, give cause for concern. The first is the decision in Applied Energy Services (AES) v. Oklahoma Corporation Commission, 31 FERC ¶ 61,313 (1985). What led to this case was the issuance by the Oklahoma Corporation Commission of Rule 58(H) in which the Commission asserted the right to include in any QF contract its authority to set aside at a later date any provision, including the rates, of any contract between a utility and a QF even though the Commission had earlier approved that rate or other provision. This provision is a clear violation of the FERC rule providing that a QF has the option of: (1) providing energy "as available" to a utility, in which case the rate for purchase would be calculated as of the time of delivery of the energy, or (2) providing energy or capacity pursuant to a legally enforceable obligation over a specific time period, in which case the QF has the additional option of receiving a rate based on the utility's avoided cost as estimated either at the time of delivery or "at the time the obligation was incurred." 18 C.F.R. 292.304(d) (emphasis added).

FERC's regulations make no provision for a state commission later to set aside a rate based on estimates, especially where the Commission has approved the rate. Obviously, if a state were able to set aside such a rate, financing, which is dependent on a secure revenue stream, would be unavailable.

When AES pressed its concern regarding Rule 58(H) at the FERC, the FERC declined to enforce its rule, as is its prerogative under PURPA, although its refusal to act was inconsistent with its own enforcement guidelines. That AES was later able to obtain a waiver of Rule 58(H) by the Oklahoma Commission for its project, as was the other early cogenerator in the state, does not mitigate the generic problem raised by the Oklahoma rule, nor does it render proper policy the FERC's failure to enforce its rule or even express concern over the Oklahoma rule.

A second troublesome case is Alcon, Inc. 32 FERC ¶ 61247 (1985). In this case, the FERC denied QF status to

Alcon's pharmaceutical plant in Puerto Rico, because the proposed cogeneration facility would be developed by a third party. The FERC ruled that only the third-party owner of the facility could obtain QF status in this instance, even though that facility would sell steam and electricity to Alcon and use Alcon's land. The FERC held that Alcon was not entitled to back-up power from the local utility, as it would have been if it were a QF. FERC also found that if the third-party owner of the facility itself purchased the back-up power from the utility and resold it to Alcon, even at no profit, the third-party owner would become an electric utility and thus lose its QF status. This Catch-22 decision, which we believe to be wholly inconsistent with PURPA, jeopardarizes third-party financing of QFs, and is causing turmoil at state commissions, to which QFs turned for relief. */ (The FERC apparently reached a consensus, although no vote was taken, at its June 25, 1986, session to reverse this holding, ten months after the initial decision, and two-and-one-half years after Alcon's application was filed.)

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*/ Commissioner Stalon wrote a stinging dissent arguing that the majority's decision was contrary to PURPA and expressing concern that the holding would "provide an unnecessary barrier to the full development of economic cogeneration potential that Congress, in enacting Section 210, charged us to encourage." 32 FERC at 61,581-7.

These cases and others give us concern about the FERC's commitment to the letter and spirit of PURPA. Together with developments in tax policy and avoided cost levels, they indicate that the climate for efficient cogeneration and small power production is not favorable. We urge Congress to consider these developments in its review of PURPA implementation.

III. THE PURPA IMPLEMENTATION RECORD

This Chapter expresses the firm's perspective on PURPA implementation to date, gained by representing numerous QFs over a period of several years and based on first-hand, albeit anecdotal, information.

A. QF-Utility Relationship Requirements Under PURPA

Under section 210 of PURPA, electric utilities are required to offer to purchase electric energy from and sell electric energy to QFs. Under FERC regulations, electric utilities are required to offer to pay for electric energy generated by QFs at a ("buy-back") rate equal to the utility's avoided costs, *i.e.*, those costs that a utility would have incurred but for the purchase of the electric energy from the QF. The avoided cost of any utility always includes variable costs, which are mostly fuel-related. It may also include fixed generation and/or transmission capacity costs, if the utility purchasing QF capacity and energy can avoid any such costs by virtue of purchases from QFs. 18 C.F.R. 292.303 *et. seq*.

As we indicated above, FERC regulations also specify that a QF has the option of: (1) providing energy "as available" to a utility, in which case the rate for purchase would be calculated at the time of delivery of the energy, or (2) providing energy or capacity pursuant to a legally enforceable obligation over a specified period, in which case the QF has the additional option of receiving a rate based on the utility's avoided cost for that period as estimated either "at the time of delivery" or "at the time the obligation was incurred." 18 C.F.R. 292.304(d).

The buy-back/avoided cost requirement applies to any utility to which a QF is able to sell its energy. The FERC's regulations do not require an electric utility to transport QF energy to other utilities, but the utility may do so with the consent of the QF.

Most PURPA implementation issues revolve around the efficiency and fairness of this ratemaking and purchase relationship.

B. General Points About Relationship Issues

1. Even though the utility industry and DOE continue to worry about the threat of long-term generation capacity shortages (see this Committee's record of hearings, "When Will The Lights Go Out?", July 23, 1985), many utilities do not include payment for capacity in their avoided cost-based buy-back rates. The result is that a considerable portion of QF capacity that has been built since enactment of PURPA will provide capacity value to utilities and their ratepayers at no cost during a time when utilities would otherwise have to build capacity at a high cost.

2. Most state utility commissions take a passive role in QF development, except for very small QFs, preferring to let most QFs privately negotiate the best deal they can with often recalcitrant utilities.

3. Generally, independent QF developers go to those states with relatively high avoided costs and cooperative utilities and utility commissions. Industries with facilities in states without these characteristics and who do not have the option to go elsewhere may build to meet their own internal load only and get off the utility system. The result in this situation is that facilities would not be optimally sized for electric output and the utility's remaining customers would end up paying for a portion of the utility's sunk costs formerly recouped from departed industrial loads.

4. Utilities have considerable bargaining leverage in negotiations with QFs. Most large QFs must have a long-term power sale contract to obtain financing to build facilities large enough to produce power exceeding internal loads, but it is the FERC's position that PURPA does not require utilities to offer long-term contracts. Nor does PURPA require utilities to arrange a buy-back payment scheme consistent with the financial needs of QFs. Utilities possess most of the information necessary to compute avoided costs and can shape that information to meet their needs. Utilities are not

required to wheel QF power to other utilities with higher avoided costs. Finally, PURPA does not expressly require states to permit utilities to pass through the cost of QF energy purchases to ratepayers. Consequently, utilities often try to impose the risk of a denial of a pass-through on to QFs; indeed, sometimes utilities try to maintain or create this risk (by not asking the state commission for advance approval) so as to be able to insist on a contract clause reducing payments to the QF by amounts not recovered from ratepayers. This kind of clause, like state reopener provisions, imposes on QFs a regulatory risk that we believe Congress intended to remove; and creates sufficient uncertainty to make otherwise sound projects non-financable.

5. The avoided cost rule is only a starting point for QF negotiations with utilities in most states. However, to QFs it is an essential source of bargaining leverage necessary to offset otherwise superior utility bargaining leverage. Most QFs end up accepting a buy-back rate established at some fraction of avoided costs in order to obtain other necessary contract provisions not required by PURPA, or at least not available without litigation. In this manner, ratepayers in many states do see some direct, and often immediate, rate benefits from PURPA QFs.

C. Chadbourne & Parke Anecdotes

1. Ohio

The firm presently represents a QF endeavoring to build a small power production facility which would use all of a major city's garbage as a fuel source. This anecdote is offered to demonstrate how the problems encountered by a QF faced with a reluctant utility and a hesitant utility commission threaten a project that not only produces electricity at a price far less than the utility's present powerplant under construction, but also serves another public purpose, that of disposing of garbage.

Negotiations with the utility began in 1983. They have foundered chronically over the issue of establishing a long-term buy-back rate. Because the proposed QF is a small power production facility larger than 30 megawatts (but less than 80 megawatts), the Commission initially refused to assert jurisdiction over setting the buy-back rate. Several months after the FERC made it clear that it wanted the Ohio Commission to determine the avoided cost rate, the Commission agreed to arbitrate negotiations between the proposed QF and the utility. However, the Commission staff was not prepared to adopt a rate methodology. As there were large differences between the parties to the negotiations, which included not only the QF and the utility but the staff and the Ohio Consumers Counsel, as well, the negotiations were brought to a halt and testimony was filed.

Eventually, the QF and the utility agreed to a buy-back rate without specific agreement on the methodology used to support the rate. The other parties agreed to this figure as well.

The rate and other elements of the agreement between the QF and utility were then placed before the Commission for its approval. The Commission and a hearing examiner involved in the case proceeded to consider the matter for one year without acting. Finally, the Commission decided to act on the matter, but then the utility announced that due to changed circumstances it would no longer honor the buy-back rate for capacity to which it had previously agreed (8.471 cents per on-peak kWh), unless the Commission expressly recognized that the utility was, with the Commission's blessing, merely sticking to the deal made a year earlier. Meanwhile, the utility had acknowledged that the capital cost of its powerplant under construction (but far from completion) would be about 18 cents per on-peak kWh. In our view, the avoided cost had gone up significantly.

Faced with the utility's reluctance to stand by its earlier agreement, and apparently unnerved by the scale of the changes in the utility's avoided cost estimate, the Commission refused to endorse the rate, except for the first five years of a 25-year contract. Instead, it issued a decision establishing a range for on-peak avoided cost rates, to vary between 5 and 9 cents per kWh, and to be set every five years by means of mandatory contract reopeners. The Commission failed to set out any methodology by which a rate within that range would be determined. We informed the Commission that this type of free-floating rate, within a range which we believe to be far below the utility's true avoided cost, and subject to change every five years by some unannounced methodology, would render the project unfinancable, and that the mandatory Commission reopener provision was in conflict with the FERC's regulations. On rehearing, the Commission merely made the range symmetrical so that the price could go up to 12 cents per on-peak kWh, instead of 9 cents, a measure of little significance, since absent either a satisfactory floor price or a determinable formula for moving within the range, the project could not be financed. The project sponsor is now trying to develop a formula to present to the Commission.

2. Vermont

We have represented two small hydro developers in Vermont. This anecdote is offered to show that the full avoided cost rule and FERC regulations endow state regulatory agencies with substantial latitude to control their local situations. Vermont may provide the best example of this flexibility, which does not always work to the advantage of QFs.

Vermont's Public Service Board (PSB) regulates some twenty-six investor- and consumer-owned electric utilities, which have a total load of about 900 megawatts. As an experimental measure, the PSB created a new entity called the Vermont Power Exchange (VPX) to act as a sales intermediary between the QFs and the utilities. The VPX ostensibly purchases all Vermont QF power and distributes it pro rata to all 26 state utilities, receiving payments from the utilities and distributing the revenues, less VPX operational expenses, to the QFs. The PSB has set state-wide, long-term buy-back rates for all QFs.

In assessing the state-wide long-run rates, an administrative law judge, on the basis of an extensive record, recommended rates equivalent to about 7 cents per kWh for ten-year contracts and up to 14 cents per kWh for thirty-year QF commitments. One month before the PSB issued its final order on these recommendations, it stated in another proceeding that it could find no new 30-year capacity available to Vermont at less than 16 cents per kWh. However, one month later, the PSB reversed the law judge in the earlier QF case and held that 10-year QF commitments would receive only 4 cents per kWh and 30-year sales commitments, only 10 cents.

The following week the Vermont Department of Public Service announced the execution of a contract with Hydro Quebec to purchase 150 MW of power for 10 years at an announced price of 3.5 cents per kWh. In a proceeding to approve this purchase, the PSB acknowledged that the Canadian purchase would actually cost Vermont ratepayers over 8 cents per kWh, after all costs and charges were considered. Nevertheless, the purchase was approved with the caveat that these costs would be taken into consideration when long-run avoided costs were next determined. Thus Vermont is now paying over 8 cents per kWh for ten years of Canadian power while offering its own QFs only 4 cents per kWh.

3. Louisiana

The firm represented an independent developer-operator in negotiations with a large investor-owned electric utility in Louisiana over the nature of the relationship between a proposed large cogeneration facility, which would be operated by the company to serve the steam needs of a chemical company. We offer the anecdote as an example of a third-party venture that could bring large rate-related benefits to the ratepayers of this utility through a long-term contract made feasible by the Simultaneous Purchase and Sale Rule, a poorly understood but important component of the PURPA program. See *infra* at 61-66.

The developer had attempted to negotiate a power sales agreement with the utility for nearly two years without success. During the negotiations, the utility generally resisted the execution of a contract with the developer, raising numerous objections, and refusing to purchase firm energy.

Eventually, we pointed out that conditions were developing that made it economically attractive for the chemical company to construct an alternative, smaller cogeneration system to serve its internal electric energy and steam needs only, and leave the utility system altogether. We also pointed out that, were it to do so, it would no longer be responsible for any share of the utility's expensive nuclear powerplant soon scheduled to come on line or, for that matter, for any other utility costs. This would have the utility's remaining ratepayers responsible for these costs.

Alternatively, we pointed out, under the developer's proposal, the chemical company could be kept on the system, and remain responsible for a share of the utility's sunk costs. The developer's proposal was to sell all of its cogeneration unit's electrical output to the utility on a long-term basis under a formula estimating the utility's avoided energy costs only (with no payment for capacity). The developer could also sell the steam generated by the cogeneration unit to the chemical company at a discount. Meanwhile, the chemical company would buy its entire electrical needs from the utility. In short, everyone would be better off: the developer, because he could make a profit on the electric sales to the utility, because its facility would be more efficient than that of the utility; the utility, because it would not lose a large paying customer (the chemical company); the chemical company itself, because it could meet its combined need for electricity and steam at a lower total cost than under its other options; and, of course, other ratepayers, because: (1) the chemical company would pay for a share of the utility's expensive generating plant; and (2) the cogeneration unit would provide uncompensated capacity value to the utility over the life of its contract.

Once the Commission staff understood this approach, it brought pressure on the utility to execute a contract with the developer and an agreement was reached. What made the agreement possible was: (1) a long-term contract buy-back rate for the cogeneration unit's power, necessary for financing; and (2) the Simultaneous Purchase and Sale Rule, which permitted the sale of all of the cogeneration unit's electrical output to the utility while, at the same time, the chemical company bought all of its electrical needs from the utility.

4. Oklahoma

The firm has represented a company in negotiations with an investor-owned electric utility in Oklahoma. This anecdote is offered to illustrate the benefits that PURPA projects can bring to utility ratepayers and the community at large.

Our client proposed to build a large coal-fired cogeneration project in southeastern Oklahoma. The project will burn high-sulfur Oklahoma coal and use Oklahoma limestone in a number of fluidized bed boilers. These units are much cleaner than conventional utility coal units and thus do not require scrubbers.

The project is expected to come on line earlier than the utility unit which it will displace. Nonetheless, to make the project financable, the utility will begin paying our client buy-back rates that include a capacity credit when the project begins generating electricity. Why would this be in the interest of the utility's ratepayers? Because, after a few years of "pre-payments," the rate paid to our client will fall below the utility's avoided cost for the remainder of the project life. In fact, the total gain to the utility's ratepayers from the project (according to both the utility and the Oklahoma Corporation Commission) when compared to utility avoided costs is about $1 billion in nominal dollars. It is noteworthy that this benefit was obtained for ratepayers in a bargaining environment in which the utility was required to offer to purchase the power output at the utility's avoided cost.

As part of the bargain, our client also agreed to permit the utility to dispatch its cogeneration unit so that the unit could be cycled along with the utility's own units. The QF will sell steam generated at the unit to a planned recycled papermill adjacent to the cogeneration unit. The QF will also use a portion of that steam to manufacture carbon dioxide (at a new plant) for use in industrial processes. The combined economic effect of the cogeneration unit and additional industrial activities it has spurred will lower utility rates below what they otherwise would have been, add enormously to the area's tax base, and offer employment to many in an area that has been economically depressed for several years.

During the negotiations between the QF and the utility, the Oklahoma Commission issued Rule 58(H), which would permit the Commission to reopen, at a later date, any contract entered into by a QF and utility. See supra at 23-24. This rule threatened the financing of the project because investors of an unregulated, single-asset entity cannot live with the possiblity that a utility commission will set aside an agreed upon buy-back rate at some time in the future. In vain, we sought to have the FERC enforce its regulations that entitle a QF to depend on a buy-back rate based on an estimate of avoided costs made at the time of contract. Eventually, the Oklahoma Commission issued a waiver of Rule 58(H) for this project. Without the waiver, the project would not have been possible.

D. Pfeffer, Lindsay Report Anecdotes

The Pfeffer, Lindsay & Associates, Inc. Report (the "Report" or "Pfeffer, Lindsay Report") is the result of a substantial effort to describe PURPA implementation efforts to date. The firm agrees with the central conclusions of the

Report regarding the relationship requirements described in Section A of this Chapter that:

-- the states seem to be correcting problems raised in early implementation; and

-- major surgery on PURPA is unwarranted at this time.

Chapter VI of the Report is a series of PURPA implementation anecdotes taken from various states. The anecdotes are described as examples of states' establishing rates alleged to exceed avoided cost. The firm finds many of these anecdotes misleading because they mischaracterize the facts or are incomplete or unrepresentative of PURPA implementation in general, and even in the states from which they are chosen. In this section, we comment on these anecdotes to offer the firm's perspective on PURPA implementation in these states. We discuss these anecdotes in the order in which they are presented in the Pfeffer Report.

1. Kansas

Chapter VI begins with an anecdote from Kansas in which an attempt by the Kansas Commission to establish QF rates above avoided cost to promote QF development was arrested by litigation brought by Kansas City Power and Light (KCP&L). The buy-back rate struck down by the Kansas court was significantly less than the cost per kWh of the utility's interest in a nuclear powerplant which was under construction at the time.

To the firm, what is remarkable about PURPA implementation in Kansas is the strength with which one utility has fought to prevent implementation of the statute through challenges in the courts. First, KCP&L challenged the Kansas Commission's implementation of buy-back rates that arguably exceeded the utility's avoided cost because they required a small payment for capacity. The Kansas Supreme Court, relying on a decision by an intermediate New York State appellate court that was later reversed by the New York Court of Appeals (New York's highest court), ruled that PURPA effectively prohibited the states from setting buy-back rates in excess of avoided costs. The Commission did not appeal this decision.

Despite the fact that the U.S. Supreme Court had already found PURPA to be constitutional in FERC v. Mississippi, 456 U.S. 742 (1982), the utility then sought a separate judgment from the Kansas court that PURPA was unconstitutional because, among other reasons, it permitted a taking of its property without due process of law. The Kansas Supreme Court rejected this argument, but KCP&L has recently asked the U.S. Supreme Court to review this decision. This litigation continues to be a cloud on PURPA implementation in the United States.

2. New York

The 6 cent rule in New York State and litigation triggered by it are discussed in the Report as an example of a state that has prescribed buy-back rates for QF electricity that exceed avoided cost.

The situation in New York is a good deal more complicated than the Pfeffer, Lindsay Report suggests. First, 6 cents is from time to time, in some hours, above the avoided cost of some utilities, not counting new generation capacity that will be needed over the long run to meet load. In other words, 6 cents, from time to time, may exceed avoided operating or energy costs only, but in no way exceeds utility avoided energy and capacity costs over the life of QFs now coming on line. At present, most New York utilities have a surplus of generation capacity and thus present actual avoided costs may not include generation capacity costs. However, according to the U.S. Department of Energy, if demand grows as forecasted by the U.S. Energy Information Administration */, New York is in a region that will need additional capacity (beyond that on which construction has already begun) by 1993. In fact, New York's utilities have reported record peak load growth in the last two years. Indeed, the New York State

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*/ "A Look at National and Regional Electric Supply Needs", J. Steven Herod and Jeffrey Skeer, Office of Coal and Electricity Policy, U.S. Department of Energy (Revised July, 1985) p. 7.

Energy Research and Development Authority has advocated increasing the state minimum payment to 8 cents per kWh to reflect the value of and need for additional generating capacity. These facts suggest that QFs coming on line deserve some payment for capacity to reflect avoided capacity savings which they will accord the region's utilities over most of their lifetime. They also suggest that the 6 cent rate is too low to encourage all cost-effective QF capacity.

Second, the benefits of the 6 cent rule are illusory because it is available only as long as the 6 cent rate remains law. Investors cannot rely on the rate because that law could change at any time. Thus, the law has not succeeded in attracting long-term QF capacity to New York markets.

Third, many QFs have had difficulty in New York State because of the inconsistency of New York Public Service Commission policy as to the types of QF utility contracts that the Commission will accept. The Commission seems to have decided to favor small hydro development, but to discourage development of any projects larger than 5 megawatts of any kind. Thus, overall, the significant potential for QF development in New York has not been realized.

On March 27, 1986, the Commission issued an order in which it clarified that it would accept contracts between QFs and utilities that included a credit for long-run generation capacity in apparent recognition that QFs soon will enable New York utilities to avoid investment in generation capacity. Opinion and Order Adopting Long-Run Avoided Cost Estimates, New York Public Service Commission, Opinion No. 86-6 (March 27, 1986).

3. Montana

The Report's description of state implementation of PURPA in Montana is out-dated and incomplete, and thus leaves an inaccurate impression of the state's PURPA policies.

The Report criticizes the Montana Commission's decision requiring a utility to enter into a fifteen year contract with a QF, with a buy-back rate reflecting the capacity costs of Colstrip 3, a unit that the Commission had excluded from rate base as "excess capacity." Montana Public Service Commission, Docket No. 84.11.71.

However, in March of this year, the Montana Commission expressly changed its policy on buy-back rates:

> The Commission finds inappropriate some parties' proposals to continue tariffing avoided cost price based on the escalated costs of Colstrip 3 and/or 4. MPC and PP&L presently have adequate baseload generating capacity, and have no plans to add additional baseload coal-fired generation plants in their respective long range plans. To invest the economy's scarce resources, based on those costs, would result in unnecessary social investments and, in addition, would be burdensome to MPC's and PP&L's ratepayers.

Investigation of Electric Avoided Cost Rates, Order No. 50916 (March 7, 1986) at 77-78 (emphasis in original).

The Commission then specified two avoided-cost-based tariff options, one based on a rate that includes a capacity credit that may be discounted if the QF is to come on line prior to the time a utility needs the capacity; the other, based on the result of negotiations between a QF and the utility. Thus, Montana seems to have realized the earlier inconsistency of its approach to QF rates and utility capacity rate treatment and adjusted its regulation accordingly.

4. Iowa

Events have also moved beyond the Report's description of PURPA implementation in Iowa. The Report relates utility concerns with, among other things, the Iowa Commission's uniform, minimum buy-back rate of 6.5 cents per kWh. The Report indicates that the Iowa utilities had challenged the Commission's rule, arguing first, that the PURPA ceiling on buy-back rates was intended to preempt the states from setting rates above avoided cost; and, second, that even if Iowa could, consistent with federal law, establish a buy-back rate above avoided cost, the Commission had exceeded its authority under Iowa law.

On March 26, 1986, an Iowa District Court ruled against the utilities on the preemption issue, but sustained their challenge under Iowa law. The result is that the 6.5 cent rate, which applied only to renewable resource QFs in the first place, has been set aside and the entire matter sent back to the Commission.

5. Indiana

The Report indicates that Indiana utilities had lodged a challenge against Indiana PURPA regulations. On May 7, 1986, the Indiana Court of Appeals rejected that challenge without reaching its merits. Indiana and Michigan Electric Co. v. Indiana PSC, 492 N.E.2d 323 (1986).

6. Maryland

The Report describes what it calls an "especially noteworthy" decision by a Maryland hearing examiner setting a buy-back rate above avoided cost. The rationale of the hearing examiner was that such a rate was proper because it was "needed to encourage QF development and operation." The impression left by the Report is that the hearing examiner's decision may be present policy in Maryland. It is not.

In March 1985, the Maryland Commission explicitly rejected the hearing examiner's decision stating:

> We believe that rates which are based upon avoided costs will encourage the development of economical and reliable QFs, while at the same time, not require the imposition of additional financial burdens on the utility's customers.

Proposed Generation and Small Power Production Rate Schedules of the Potomac Edison Company, Order No. 66957 (March 4, 1985) at 7.

7. New Mexico

The Report relates the fact that some QFs in New Mexico believe that they are entitled to capacity credits. The firm is unaware of any QFs that presently sell power to any New Mexico utilities at a buy-back rate that includes a capacity credit, even though New Mexico utilities have continued to build and plan for new generation capacity to meet regional loads. In fact, QF development in New Mexico is very limited, in part because no capacity credits are generally available.

8. Oklahoma

The Report describes an Oklahoma case in which, in order to reflect "the ecological benefits to society . . . if sanitary landfills are not utilized," Oklahoma Gas and Electric (OG&E) was ordered to pay a solid waste burning QF a buy-back rate that may have exceeded avoided cost. Oklahoma Corporation Commission, Application of CMP Energy Conversion Systems for Establishment of Purchased Power Rates, Case No. 29259 (November 1984).

The Report leaves the impression that Oklahoma is in the habit of requiring utilities to pay rates in excess of avoided costs. In fact, this case is anomalous in Oklahoma but, nonetheless, is a good example of why states should be free to establish rates that exceed avoided costs for valid local public policy reasons. See footnote at 16, supra.

The extra payment required of OG&E in this case reflects the fact that the benefits attributable to the waste-burning QF at issue in this case extended beyond the utility's avoided cost to savings to Oklahoma City from avoiding the cost of waste disposal by landfill. The Commission computed the extra payment so as to reflect the extra benefit that would be reaped. Then the Commission implemented the higher buy-back rate for ratepayers in Oklahoma City only, so that the extra cost associated with the above-avoided-cost rate would fall only on those who directly benefited from the facility's waste-disposal. In this manner, the Commission provided an economic incentive more closely related to the total benefit the public would derive than if the buy-back rate were based on the QF's effect on utility generating costs only. The firm believes that the Commission's decision represents excellent policy. It is noteworthy that no party appealed this decision.

9. Maine

The Report accuses the Maine Commission of having confused "sunk" with avoidable costs by declaring the costs of Seabrook Unit 1 to be unavoidable in a Central Maine Power

Company case, while declaring such costs to be avoidable in a later case dealing with Maine Public Service Company.

What really happened was that in the second case the Maine Commission determined that, based on a fresher and more complete record, Seabrook 1 costs were avoidable, at least to Maine Public Service Company, because the Commission believed that the company could sell its interest in that Unit. In the first case, the Commission had concluded that the cost of Seabrook 1 was not avoidable because of a then-perceived glut of power in the Northeast and because the plant was not as near completion. Thus, the Commission did not confuse sunk with avoided costs. It merely adopted a new view, based on new and additional information, that the cost of Seabrook 1, which it had previously found unavoidable, was, indeed, avoidable. Maine PUC, Docket No. 81-276, Maine Public Service Company (February 10, 1984); Maine PUC, Docket No. 82-174, Central Maine Power Company (January 9, 1984).

10. Idaho

The situation in Idaho is somewhat different than that described in the Report.

Idaho has required utilities to offer contract rates to QFs since 1980. With the benefit of hindsight, it appears that the long-term contract rate embedded in early Idaho QF contracts exceeded the avoided costs that have actually been experienced by Idaho utilities. The entire Pacific Northwest, including particularly, and for the longest time, its utilities, expected capacity shortages in the 1980s. Instead, the region has been characterized by a surplus which may endure into the 1990s. The unexpected surplus of power in the Northwest has caused actual avoided costs to fall below some previously-established QF buy-back rates.

However, the rates embedded in existing QF contracts remain at the same nominal level throughout the contracts. Idaho and the other Pacific Northwest states will need additional generating capacity at some time in the future. At that time, existing QF capacity under early 1980s contract rates will likely look very good to Idahoans.

Recently, the Idaho Commission brought contract rates in line with presently experienced avoided costs. Thus, the current, standard 20-year contract rate calls for payment at 2.9 cents per kWh, not the 6 cents plus per kWh referred to in the Report. Even 35-year contract rates are set at only 4.4 cents per kWh. It is difficult to imagine that these rates will not provide significant rate benefits to Idaho consumers for most of the operating lives of the QFs .

Finally, the Report cites Afton Energy, Inc. v. Idaho Power Co. ("Afton II"), Idaho Supreme Court, Opinion No. 82 (July 12, 1984), as authority for the proposition that the Idaho Commission may modify previously-established contract buy-back rates that exceed present estimates of utility avoided costs. This is incorrect.

The Idaho Court revisited this decision in December, 1984, and found that the Idaho Commission could indeed review existing buy-back rates, but only in a manner consistent with federal law. Afton Energy, Inc. v. Idaho Power Company, ("Afton III") Opinion No. 167 (Dec. 20, 1984).

Afton III was, as the Court stated, a modification of Afton Energy, Inc., v. Idaho Power Co., 693 P.2d 427 (1984) ("Afton I"). That opinion contains a long discussion of the FERC regulations specifying that a QF has the option of contracting for an avoided cost rate based on a utility's avoided cost as estimated at the time the contractual obligation is establishied. Therefore, Afton III stands for the proposition that while a state may certainly review contract terms at any time under state law, it may not set aside an established rate if to do so would be inconsistent with federal law as codified in FERC regulations.

11. Colorado

The Report relates a decision by the Colorado Public Service Commission requiring Colorado Public Service Company to escalate capacity payments over the life of a QF. Colorado PSC, Decision No. C82-1637 (October 14, 1982). The impression created by the Report is that the policy of escalating buy-back rates over the life of the QF in light of increasing marginal capacity costs -- a policy that appears erroneous to us -- may be Commission policy in Colorado. In fact, the Commission has not used the methodology discussed in that case in any other QF cases it has handled. Moreover, the QF which was the subject of that order never came on line and, thus, ratepayers will not be injured by the rejected methodology.

12. California

The Report contains a lengthy anecdote regarding PURPA implementation in California. The Report describes events leading up and subsequent to the Commission's suspension of standard contract offers that included capacity payments.

The California experience is used by friends of PURPA as an example of how successful PURPA can be in encouraging decentralized electricity generation, and, by its foes, to show what is wrong with PURPA. The key facts are these:

1. As of the end of 1985, there were 2875 megawatts (MW) of QF capacity on-line in California. This compares with California peak demand of about 38,000 MW.

2. About one-half of this QF capacity is co-generation or biomass capacity. The other half is mostly wind and small amounts of hydro, geothermal and solar.

3. There is also about 12,800 MW of QF power that has not been developed, but which was under signed

contract with California utilities. About 60% of this capacity is cogeneration or biomass-fueled. Most of the cogeneration capacity is gas-fired. About one-quarter of the total capacity under contract but not on-line is wind capacity and the remainder is hydro, geothermal and solar.

4. Contracts for a substantial portion of the 12,800 MW were executed under a Standard Offer (No. 4) at a time when, fueled by Commission acknowledgement that the offer had encouraged more QF capacity than had been thought possible, rumors circulated that the Commission was considering suspending that offer. The Commission eventually did so on April 17, 1985. More recently, the Commission suspended Standard Offer No. 2 as well, which also required payment of capacity credits. Unlike Standard Offer No. 4, however, Standard Offer No. 2 was suspended swiftly, without rumor, and without an eleventh-hour rush to sign up for it.

5. If all 12,800 MW of new, contracted-for capacity were to come on line during the required five-year period subsequent to execution of contracts, California might have excess electric generating capacity perhaps into the 1990s. Most observers believe, however, that only a fraction of that capacity will actually be developed, much of it having been encouraged by the "gold rush" environment created by rumors of suspension of Standard Offer No. 4. Thus, while California has a surplus of contracts, it may not have a surplus of QF capacity.

6. The average cost of QF capacity under contract to California utilities and on-line is about 6 cents per kWh. This compares with an average California investor-owned utility retail rate of around 9 cents per kWh, and avoided cost rates ranging from 7 to 8.5 cents per kWh in 1982. In recent months, avoided costs have fallen to as low as 2 cents per kWh (with no capacity credits).

7. The full cost of the most recent California utility generating facility resource constructed, the Diablo Canyon nuclear plant, has been estimated on the basis of utility data to equal 11.2 cents per kWh on a levelized basis.

What kind of a story do these facts tell? First, they indicate that there is tremendous potential for QF development in California at prices that compare very favorably with a recent utility generating resource. Second, they indicate that some QFs hold contracts with buy-back rates that appear to exceed the present level of avoided cost. (However, they do not demonstrate that ratepayers presently are paying for massive amounts of QF power at rates that are higher than they would be otherwise. Nor do they show that there will likely be large rate penalties imposed upon California ratepayers due to QF power purchases.) Third, they indicate that the California Commission could have administered PURPA more effectively by acting decisively after having realized that its Standard Offer No. 4 was attracting more capacity than the Commission had expected. Fourth, they show that the Commission appears to have learned from its experience.

13. Other State-by-State Anecdotes

The Report refers to an order of the Connecticut Department of Utility Control (DPUC) which was criticized by Northeast Utilities for establishing buy-back rates in excess of those needed to attract capacity. We find this anecdote unrepresentative of PURPA implementation conditions in Connecticut.

The firm has represented two coal-fired cogeneration QFs in Connecticut, both proposing to sell power to Northeast Utilities. Our impression is that Northeast Utilities' estimates of avoided costs were well below true avoided costs. In any event, one project with which the firm is associated has signed a contract with Northeast, and the other has signed a letter of understanding. One of them is estimated to save Northeast ratepayers about $2 billion in nominal dollars over the life of the project compared with Northeast's own public estimates of avoided cost; both provide significant dispatchability to Northeast.

The DPUC is evaluating the projects that reached agreement with Northeast under the criticized order for consistency with Connecticut law and policy; it has made it clear that not all projects claiming such rates will receive them; and it will soon adopt new and lower buy-back rates.

The Report also describes the New Jersey Master Plan procedure. It asserts that if certain features of the Plan were adopted, New Jersey utilities might be subject to additional competition from QFs, even to the point of bumping existing utility capacity from rate base, if New Jersey utilities could not compete effectively with QF power. Whatever the wisdom or legality of the New Jersey Master Plan as proposed, it must be noted that the policies that it contains regarding the treatment of existing utility investment do not raise PURPA issues. Those aspects of the Plan that do relate to PURPA are proposals only, and will be subject to review by the state and to New Jersey Board of Public Utilities (BPU) hearings before they are implemented, if at all.

In any event, New Jersey utilities do not appear threatened by QFs. For example, Atlantic City Electric Company (ACE) recently agreed to a contract with a cogenerator which ACE calculated in a special study would save its ratepayers over $40 million. Despite the vigorous support of this deal by ACE, the BPU disapproved it, ostensibly because the price exceeded the BPU-established, state-wide avoided cost methodology, which is simply the rate at which New Jersey utilities buy spot energy from the multi-state power pool, plus 10%.

The Report discusses Florida PURPA implementation in a number of places. While we believe that the Florida

Commission has generally been supportive of QF development, it has implemented a requirement regarding capacity credits that is not at all favorable to QFs. Florida reduces allowable capacity credits by 20-40% of avoided capacity costs in order to reflect the risk that an insufficient number of QFs will actually come on line to enable Florida utilities to avoid capacity. The problem with this approach is that it effects a self-fulfilling prophecy: if capacity payments are set too low, investment in QFs will be discouraged and, indeed, there may not be sufficient QF capacity to enable generation capacity to be avoided. Moreover, there is no reason to believe that QF capacity is any less reliable than utility capacity; indeed, it is probably more reliable. See infra at 69-70.

E. Summary

We think that the anecdotal information discussed in this Chapter points out the following about PURPA implementation:

-- PURPA can bring -- and in fact has brought --significant benefits to ratepayers, the general public, utilities and, of course, QFs;

-- PURPA implementation has not always been smooth. Both utilities and QFs can cite examples of implementation that has favored one or the other; and

-- Many of the states that initially had problems in implementing PURPA (problems of inadequate, as well as excessive, encouragement) have learned by their experience; for the most part, today, states are faring quite well in implementing PURPA.

IV. TEN COMPLAINTS ABOUT PURPA AND RESPONSES TO THEM

This Chapter raises and responds to the most frequently heard complaints about PURPA and its implementation.

Complaint #1: Ratepayers have been obligated to subsidize QFs by the establishment of buy-back rates above true avoided cost, either through the intentional establishment of such rates or through miscalculation. The problem has been compounded by long-term fixed-rate contracts between QFs and utilities which have locked in rates above avoided cost for the life of the contract.

Response: As a general matter, the facts just do not support this complaint.

First, there are few examples in which buy-back rates have been established deliberately at above estimated avoided cost. We believe states properly have the authority to set rates above avoided costs if separate state authority exists. However, we believe that authority should be exercised cautiously and sparingly.

Second, most states, as we indicate above, leave the establishment of buy-back rates to negotiations between utilities and QFs. It is our experience that utilities do not knowingly overstate their avoided costs in order to help their competitors.

Third, the estimation of avoided costs estimates for future years is more of an art than a science. Some states, like virtually every utility we know, estimated that fuel costs would be higher than they turned out to be, and that generating capacity surpluses would not endure as long as they have. Thus, it should not be surprising that in some of the states that aggressively promoted PURPA QFs, avoided-cost-based buy-back rates were, temporarily, higher than actual avoided costs. However, we are unaware of any state that has not taken steps, some of them in the last few months, to reestimate avoided costs in light of new information about fuel prices and capacity needs. We believe, however, that the amount of QF capacity that will actually operate under buy-back rates exceeding the utility's avoided costs is miniscule. Moreover, payments above avoided costs are likely to be temporary phenomena because utility fuel costs will eventually increase, and many QFs will provide capacity value at little or no cost to ratepayers as utility reserve margins shrink over time. As the preamble to the FERC rule states, "in the long run, 'overestimates' and 'underestimates' of avoided costs will balance out." (Regulations Preambles, 1977-1981, ¶ 30,128 at 30,880).

Concern over buy-back rates fixed by long-term contracts -- which are essential to obtaining financing for many large QFs -- bears special mention because this issue has been blown out of proportion.

First, as we indicate elsewhere, most -- indeed, in the experience of the firm, nearly all -- fixed buy-back contract rates are considerably below utility and Commission estimates of avoided costs.

Second, with a fixed-rate contract, ratepayers are assured that they will not have to pay more for QF energy than the amount agreed to by contract. No such assurance, of course, exists with utility resources, as the record of utility cost overruns over the past ten years painfully demonstrates.

Finally, fixed buy-back rates are typically paid solely on a cents-per-kWh basis; that is, QFs get paid only for electricity actually delivered. Utilities, on the other hand, receive a return on new plant from the time that the cost associated with the plant is placed in rate base, whether or not the unit is generating power. Thus, QFs have more of an incentive to perform reliably; this reliability gives additional value to utility ratepayers.

Complaint #2: The Simultaneous Purchase and Sale Rule allows QFs to reap a windfall from utilities and ratepayers that is unnecessary to encourage QF development.

Response: The Simultaneous Purchase and Sale Rule is one of the most poorly understood components of the PURPA program, and its effect has been subject to considerable misinterpretation. The rule simply allows a QF to sell all of its electrical output to the utility at the utility's avoided cost, and purchase all of its internal need for electricity from its utility at the utility's regular retail rate. At first blush, this rule strikes some as unfair: why should a QF be paid for all of its electrical output at avoided cost, say hypothetically 8 cents per kWh, while it purchases all the energy it needs to run its industrial or other processes from the utility at, typically, an average-cost rate that is less than avoided cost, say 4 cents per kWh? Is not the 4 cent difference between the avoided cost and retail rate an unnecessary subsidy or windfall from the utility to the QF? No, it is not.

The difference between the two figures is that the four cent rate at which the utilities sell electricity to their retail customer is generally an average cost rate. A utility's avoided cost -- the price that a cogenerator is paid -- on the other hand, is based on the utility's highest cost generating unit, in terms of both fuel and other operating and capital costs.

This is appropriate, because if an industrial customer of a utility paying average cost rates were to begin to generate electricity for sale to the utility, the utility would not save or avoid its average cost. Rather, the prudent utility would turn off its most costly generating unit. Thus, for example, if the utility's highest cost unit produced electricity at eight cents per kWh, that is the rate at which the utility would save if it obtained the same kWh from the QF. Thus, if the industrial facility sold its output to the utility at eight cents per kWh, making it unnecessary for the utility to generate electricity at the same cost, the rates to the other customers would be unchanged: the average cost of generation of electricity to the utility would still be four cents per kWh.

Another example is where the utility has an upcoming capacity deficiency. An industrial concern can build and operate a generating facility for seven cents per kWh, and the utility, faced with building a new unit unless it finds an alternative supply, will have to spend eight cents or more per kWh to build and operate a new facility. Since the utility has a large existing base of older, depreciated plant, this will only increase its average cost by a little, say to 4.5 cents. If the industrial concern were required to consume its own output to meet its own load, and were allowed to sell only its surplus at eight cents per kWh, it would be unlikely to build a facility at all: it would have to sell electricity to itself at seven cents per kWh for all its plant usage, and thus forego the opportunity to buy from the utility at four to 4.5 cents. Even if the utility were building twelve or fifteen cent per kWh plants, its average cost, because of its large capacity base, is unlikely to go up to more than, say five or six cents. In this situation, were it not for the Simultaneous Purchase and Sale Rule, the cogenerator would have to forego four to five cent power from the utility for its own electric use, and instead purchase from itself at seven cents. It would not do so, and thus the utility would build the more expensive plant, and economic efficiency would suffer. If, on the other hand, the industrial concern sold all of its output to the utility at eight cents per kWh (the utility's avoided cost), other ratepayers would pay the same or less for power than they would have had the utility built its unit. Society at large would also benefit if the more efficient producer, the industrial facility, built the new plant rather than the utility, which is the less efficient producer.

Perhaps a more common circumstance these days is where a utility brings into service a very expensive new plant which drives retail rates up sharply. In this situation, the industrial concern is likely to build and operate a cogeneration facility in large part to reduce its purchases from the utility. Since the utility's costs are in significant part fixed, and its retail sales go down when the industrial concern leaves the system or reduces its purchases, those fixed costs must be spread over reduced electric sales, thus increasing the burden on the utility's captive (non-self-generating) customers. We are familiar with a few cases in which the Simultaneous Purchase and Sale Rule has preserved a utility's existing sales base, despite sharply increased retail rates, because a cogeneration developer sold all its output to the utility at the utility's avoided cost, and its associated industrial concern continued to take all of its electric needs from the utility, thus sparing the utility's captive customers the burden of paying for more of the utility's fixed costs.

The FERC believed, and we still agree, that in the long run greater efficiencies are likely to be achieved if one treats distinctly the electricity production of cogenerators and the electricity needs of their associated industrial facilities. */

In the firm's Louisiana anecdote, described supra at 35-37, utility avoided costs were actually below average costs. Yet, the rule was still critical to the

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*/ The propriety of the Simultaneous Purchase and Sale Rule from an economic efficiency perspective is rooted in the virtues of the avoided cost rule discussed supra at 13-16. The Simultaneous Purchase and Sale Rule, however, merely assures that all cogeneration potential, not just the cogenerator's output which is not consumed by its host industrial facility, receives the proper economic signal to develop. In addition to this economic efficiency justification for the rule, the rule spares ratepayers the rate burden that would result if industrial facilities left the utility's system to engage in independent self-generation and consumption.

ability of the parties to reach agreement in that case because it enabled the host chemical company to depend entirely on the utility for its internal electric needs, while the QF sold all of its electrical output to the utility. As we described above, the project at issue in Louisiana has important ratepayer and public benefits.

In sum, the Simultaneous Purchase and Sale Rule contributes to both economic efficiency and fairness.

Complaint #3: PURPA requires utilities to purchase QF energy even when they do not "need" it.

Response: It is almost always beneficial for a utility's ratepayers if the utility purchases QF energy at buy-back rates equal to or less than that utility's avoided cost, whether or not that utility has a present "need" for additional generating capacity. (There are, however, short-lived situations in which dispatch conditions cause avoided energy costs to be negative.) As long as a utility avoids some cost (e.g., fuel cost) as a result of purchasing electricity from a QF, it will be no worse off if it buys QF energy at a rate equal to or below that cost. Thus, utilities almost always need energy that they can buy at avoided cost or less. Additionally, if a utility can encourage QF development by paying a buy-back rate that does not include a capacity credit, it will have encouraged the construction of generating capacity at no capacity cost to its ratepayers.

Complaint #4: PURPA requires utilities to offer to pay QFs a buy-back rate equal to avoided cost even though some lower rate may be sufficient to attract adequate capacity. "Bidding" procedures in which utilities select QFs based on the price of QF power could help overcome this problem, but there are questions as to whether PURPA permits bidding.

Response: In general, FERC's rules implementing PURPA require utilities to offer to pay every QF avoided cost buy-back rates, but the rules permit QFs and the utilities to enter into contracts that vary from the rules, 18 C.F.R. 292.301(b). Moreover, as we have indicated, most QFs take a cut from the required rate to receive concessions on other aspects of their relationship with utilities not required by PURPA. Thus, ratepayers do in fact share in the profits of many QFs from the start. Therefore, we are dubious of the need for bidding procedures.

In addition, bidding presents several problems. First, were bidding to be implemented, most utility commissions would give the task of implementing the system to the utilities. We believe that this would result in unintended re-enforcement of monopsonistic utility power which, in turn, would stifle competition in bulk power supply markets.

Second, since QFs differ not only on price but on reliability, dispatchability, seasonal and daily output characteristics, fuel use, length of commitment, and other non-price variables, price could not be the only criterion for choosing among competing bidders. Consideration of other variables would make the selection process more complicated. Simply put, utilities would be tempted to play QFs against one another based on non-market factors, such as whether the utility had an interest in the QF, or other factors that might not be in ratepayers' interest. Opening the transmission grid to QFs would alleviate this problem to an extent, but would not overcome it because all vertically integrated utilities, whether they are directly connected to a QF or not, have an interest first in earning a return on their own investment in generation facilities, rather than creating conditions that allow others to enter the market. This means that utilities naturally will favor QFs in which they have an interest.

Third, the existence of a bidding procedure would no doubt encourage the submission of bids by QFs whose ability to generate at low costs may be suspect, thereby ousting more reliable, but more costly, generators until it is too late to avoid high-cost utility construction.

Finally, bidding may well discourage less-developed QF technologies or high capital cost/low energy cost technologies from reaching the market, particularly those that need a higher buy-back rate (but still one at or less than avoided cost) to be economic.

For these reasons, we believe establishing of a bidding system is not advisable at this time. Nonetheless, the avoided cost rule is not written in stone. Like many aspects of PURPA as it presently exists, the present policy is proper in this transitional period between the old economics of utility resource investment that began to end in the early 1970s and the coming era of competition among deregulated bulk power suppliers. The new era will likely be characterized by conditions in which the exercise of monopsonistic and other market power will be less likely to threaten the integrity of bidding systems. The industry has not reached this stage yet, however, and thus institution of bidding arrangements would actually reduce the economic efficiency gains from PURPA, because fewer facilities would come on line, thus reducing the aggregate production efficiency improvements, including external benefits, from PURPA.

Complaint #5: QFs are less reliable than conventional utility generation.

Response: The evidence does not support this assertion.

First, on a short-run, day-to-day basis, at least some kinds of QFs, notably industrial cogenerators whose primary product production is round-the-clock, have availability factors as high or higher than those of utility baseload powerplants.

Second, over the long-run, at least project-financed QFs -- which comprise the bulk of large cogenerators -- have a strong incentive to stay on-line in order to generate revenue to pay off long-term debt, and once the debt is paid off, to increase profitability.

Third, QFs typically are smaller in size than utility generating facilities. The statistical probability of a massive and crippling system outage decreases as the size of individual generation installations decreases. Thus, all else being equal, QFs should increase system reliability.

Fourth, contract provisions can ensure that it will always be in the QF's interest to generate and to be available when needed by the utility. (Where there is a real question of the availability of a QF during peak hours, or of a QF's long-run reliability, a utility legitimately may include in a long-term contract appropriate sanctions to apply in the event that the QF is not on-line when needed -- up to the availability standard met by the utility's units.)

In short, we do not see reliability as a major problem.

Complaint #6: The buy-back requirement poses problems for utility resource planning and is bringing on generation not subject to the control of utilities.

Response: PURPA represents a marked change for utilities, particularly in those few states in which considerable QF capacity has been attracted to the grid. Thus, it is not surprising that some utility officials have complained about the effect of PURPA on planning, resource acquisition, and system operation.

PURPA may complicate resource planning for some utilities -- this is, perhaps, a necessary effect of competition -- but we believe that it reduces the risk in resource acquisition for utility ratepayers. First, there are no cost overruns associated with QF capacity. The QF is locked into a price; there is no QF bailout if its costs exceed original estimates. Second, as we stated above, QF capacity usually comes on-line in smaller increments than conventional utility capacity. This helps alleviate the situation in which a utility unit is brought on line and its entire cost placed in rate base even though not all of its capacity is needed immediately. The rate effect of this "lumpiness" of utility resource additions is aggravated by the fact that nearly all such additions are front-end loaded when added to rate base, thereby creating the problem of rate shock. Much large QF capacity, on the other hand, is acquired under levelized rate structures, which means that the capacity payment is lower than typical utility front-end loaded rate treatment.

The addition of small increments of QF capacity to a utility system usually causes no problems in overall system operation. What local problems it may cause usually are interconnection-related. Responsibility to pay for solving these problems lies with QFs under FERC and state regulation.

The addition of significant amounts of QF capacity may raise questions of the adequacy of system transmission capacity and use of that capacity; and may lead to an increased incidence of "light-loading" problems (when the utility's avoided costs are negative for a few hours). The first problem is increasingly being resolved by QF construction of transmission lines and sophisticated wheeling and "banking" arrangements. The second problem similarly is usually settled through dispatchability provisions in QF contracts. Also, the FERC rules provide that utilities need not buy QF output during light-loading periods. If real problems arise, it is our experience that they can generally be resolved equitably through negotiation and state mediation.

Complaint #7: Development of economically efficient QFs is impeded because PURPA does not require a utility to wheel QF energy to a distant utility with higher avoided costs than those of the utility in whose service territories QFs happen to be located. In addition, PURPA does not require the utility to wheel QF energy to ultimate customers of that utility that seek lower-priced electricity. This is an impediment to competition between utilities and QFs.

Response: Wheeling of QF energy to a distant utility with higher avoided costs promotes economic efficiency, without causing collateral problems raised by wheeling to ultimate customers of utilities. Some utilities will wheel QF power to other utilities, but many are reluctant to do so. As a general matter, utility wheeling of QF power to other utilities should be required, provided that QFs bear the legitimate cost that such wheeling entails.

Wheeling to ultimate customers of utilities raises the problem of cost-shifting, caused by the attendant loss of load to the utility, i.e., who will pay for the sunk costs formerly recouped from customers to whom QF energy is delivered? One perspective on this issue is that such customers are always free to leave or reduce their dependence on utility systems. Buying QF power instead of utility power has the same effect on the system as leaving the system for some other reason. Thus, it is arguable that wheeling to ultimate customers should be required, or at least permitted, to reflect competitive market conditions, at least where such a measure is necessary to preserve the local economic base. One way to mitigate the cost-shifting impact of this kind of wheeling would be to provide that utilities not be required to make their transmission systems available to QFs to wheel to ultimate customers when to do so would require utilities to raise rates substantially to other customers in order to recover sunk costs. Another common proposal is to permit wheeling from a QF to affiliated loads (e.g., from a paper mill cogeneration facility to a non-generating sawmill owned by the same company).

Unfortunately, the jurisdictional framework for addressing these issues is unclear. Certainly wheeling to ultimate consumers is a matter of state and local concern, but the rates for such wheeling in most situations would be set by the FERC, and the authority of the state to order such wheeling is not well-established. (It is clear that the FERC cannot order wheeling to ultimate consumers under § 211 of the Federal Power Act, the wheeling provision added by PURPA § 203.) Wheeling for QFs to utility purchasers, at least in the same state, is a matter of concern to both state and federal governments, but the authority of the FERC to deal expeditiously with such matters, and of the state to deal with them at all, is less than clear.

As we have pointed out, the direction of the utility industry is towards competition between electricity generators. We believe that Congress should be supportive of emerging competition in the electric generating industry. Removing obstacles to wheeling would further advance this cause. We acknowledge, however, that there are difficult questions pertaining to control over access to the country's transmission system, the utility's obligation to serve, and other issues that need scrutiny before wheeling to ultimate customers can be widely implemented. With respect to wheeling to remote utilities, the efficiency gains are clearer and the problems much less serious. We believe that the time is ripe for Congress to review wheeling issues, in the context of whether existing federal bulk power regulation is sufficiently flexible to permit the evolution of competition in bulk power markets.

Complaint #8: PURPA is encouraging increased use of natural gas and oil, contrary to both its original purpose and sound national energy policy in 1986.

Response: In many regions of the U.S. (*e.g.*, the Midwest), gas and oil-fired cogeneration cannot compete with utility generation and, thus, little of such QF capacity is under contract, under construction, or on line. However, there are areas, notably in Texas, Louisiana and California, where a considerable amount of gas-fired capacity has been proposed and some developed, although, particularly in California, we question how much of what has been proposed will ever come on line.

The initial question raised with respect to this capacity is whether such development is consistent with the intent of PURPA. We think that it is, because the intent of sections 201 and 210 of PURPA with respect to oil and gas was not to prevent new uses of such fuels in the generation of electricity, but to increase the efficiency of use of such fuels (cf. the cogenerator exemption from incremental pricing of natural gas in the Natural Gas Policy Act and the favorable treatment of cogenerators in the Powerplant and Industrial Fuel Use Act). Use of oil and gas by cogeneration QFs does increase the efficiency of gas and oil use through the simultaneous generation of electricity and steam. FERC's fuel use efficiency standards mandate more efficient use of these fuels than traditional utilities can achieve.

The more important question is whether QF use of oil and gas is consistent with sound energy policy in 1986. Once the price of such fuels is deregulated -- as it has been in large part -- and markets are competitive, restrictions on the use of fuel can be justified only if there is some "externality" or cost of its use that is not accounted for in the market price.

The externality most often cited in connection with gas use is that the supply of gas will be so reduced within the lifetime of gas-fired QFs that they cannot be deemed as reliable as conventional utility baseload powerplant generation. We are not experts on long-term gas supply availability. However, we do not believe conditions in gas markets warrant the imposition of restrictions on QF gas use at this time, other than those that require QF use of these fuels be more efficient than utility oil or gas use. We note that there is room in PURPA for states and utilities that believe they are becoming overly dependent on gas-fired QF capacity to require sanctions or other protective provisions similar to those discussed above in relation to Complaint #5 (on QF reliability). Such provisions should adequately protect ratepayers.

We do not believe that much oil-fired cogeneration capacity is likely to be developed in the U.S. Even in states in which conditions are most favorable for such capacity, little new large oil-fired capacity has been proposed or developed. Vulnerability to interruption due to international disputes might warrant action to restrict the use of oil in QF capacity, if the level of use of oil by QFs increases greatly. However, the inability to forecast the price of oil due to its critical relationship to imported supplies has itself prevented oil from being widely used by QFs.

Complaint #9: The limit on eligibility for PURPA benefits for small power production technologies is arbitrary.

Response: A number of PURPA's eligibility criteria for small power production technologies have drawn fire. One is the 80 megawatt limitation on eligible small power facilities, while no such limit exists for cogenerators. A second is the limitation of PURPA eligibility to a subset of generating technologies. A third is that not all PURPA benefits are available to all generating technologies above 30 megawatts. Only geothermal QFs above 30 megawatts are exempted from regulation under the Federal Power Act, the Public Utility Holding Company Act (PUHCA), and state utility regulation. Biomass facilities over 30 megawatts are exempted from PUHCA and state regulation, but not regulation under the Federal Power Act.

We see no reason to distinguish between various types or sizes of cogeneration and small power production technologies in determining eligibility for exemption from regulation and other PURPA benefits. Congress has already reached the sound conclusion that the external benefits of these technologies render them preferable to traditional utility units, so long as their costs are no higher than utility avoided costs. Thus, for example, we see no sense in favoring geothermal over other renewable resource technologies. Similarly, it seems to us, if a 29- or 79-megawatt municipal solid waste facility is a good thing, a 31- or 81-megawatt facility is at least as good. Indeed, the limits in the present law can lead to unnecessary sacrifices of scale economies, and to deliberate undersizing of a facility with respect to available resources. In light of the fact that states and local governments retain control over siting and environmental matters, and thus over whether a planned facility is appropriately sized for a particular location, we see no reason to retain the 30- and 80-megawatt size limitations.

Whether the current technology limitations in PURPA are the most appropriate is another question. We tend to agree with a recommendation made in the Pfeffer, Lindsay

Report that limitation of PURPA benefits should be a function of whether the technologies offer a special benefit, such as relatively benign environmental impact, or security of fuel supply, or need special encouragement because they are promising innovative technologies. Congress had these objectives in mind when it selected eligible technologies in 1978. Whether the selections made then are valid now is subject to debate.

We believe that, by and large, they are valid as far as they go, but they may be too restrictive. For example, as the Pfeffer, Lindsay Report points out, small power producers seeking to use coal-derived fuels other than coal waste cannot qualify for PURPA benefits, even though it would appear to be good policy to promote the development of such technologies under conditions that would protect the environment. The FERC does, however, have some latitude under current law to expand eligible fuels and technologies; and it is probably preferable to await the next stage of expanded competition and deregulation (which, if the next step is limited, need not be far off) before significantly increasing the number and type of eligible technologies.

Complaint #10: PURPA and FERC regulations restricting utility ownership of QFs to 50% are unfair and unnecessarily dampen development of beneficial technologies.

Response: We believe that restrictions on utility ownership continue to be sound public policy. First, ample amounts of capital are available for QF development without drawing on the capital resources of utilities. Second, our experience in negotiating contractual and other relationships with utilities leaves us with the impression that the temptation to favor their own projects or those of their utility neighbors would lead to discrimination against non-utility QFs. Third, we continue to believe that an original reason for restricting utility ownership of QFs -- interpreted by the FERC to allow utilities to own up to 50% of any QF -- remains sound: to disperse ownership of electric generating technology in order to stimulate competition.

When more fully competitive bulk power markets are attained, and the opportunity for utilities to self-deal is absent, it will be time to relax ownership restrictions on QFs. Until that time, they should be maintained.

V. CONCLUSION

We believe that the foregoing demonstrates that the PURPA program, as it stands, is basically sound from a public policy perspective. Thus, we do not believe that any major changes need be made to the program at this time. And we cannot express too strongly our concern that even minor changes in either the law or FERC's regulation will present an opportunity, sure to be seized, for some utilities to litigate each nuance and thus to plunge the program again into sustained and crippling litigation uncertainty.

We urge the Congress to continue to monitor implementation of the program by the states and the FERC. We believe that such monitoring over time will indicate that changes in the program in the direction not of retrenchment, but of expansion, can be made to promote additional competition in bulk power supply markets. For now, the existing program is a good step in that direction.

CHADBOURNE & PARKE

By: Rigdon Boykin
John O'Sullivan
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June 30, 1986

THE FERTILIZER INSTITUTE 1015 Eighteenth Street, N.W., Washington, D.C. 20036 (202) 861-4900

GARY D. MYERS
President

June 6, 1986

The Honorable James A. McClure
Chairman, Senate Energy & Natural Resources
Committee
360 Dirksen Senate Office Buidling
Washington, D.C. 20510

Dear Mr. Chairman:

We commend the committee for providing an opportunity to discuss issues dealing with the Public Utilities Regulatory Practices Act. In particular we appreciate the attention paid by the committee on cogeneration of electric power.

The Fertilizer Institute is the national trade association of the fertilizer industry whose membership accounts for over 95 percent of total United States fertilizer production. In partnership with our Nation's farmers, fertilizers from TFI's members contribute to our abundant supply of food and fiber. Our membership is active in the development and operation of cogeneration facilities.

On June 11, Dr. Donald Hirsch, Director of Technical Services will appear on behalf of TFI to deliver testimony in the House Subcommittee on Energy Conservation and Power. We would request that our statement also be included in the comprehensive record of the Senate proceedings. Thanking you in advance for your consideration.

Sincerely,

Gary D. Myers

GDM:pab

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STATEMENT OF DR. DONALD E. HIRSCH
Director of Technical Services
International Minerals & Chemical
Corporation
on behalf of
THE FERTILIZER INSTITUTE
before the
Subcommittee on Energy Conservation
and Power
Committee on Energy and Commerce
United States House of Representatives

June 11, 1986

The Fertilizer Institute
1015 18th Street, N.W., Washington, D. C. 20036
202-861-4900 Telex 89-2699

We very much appreciate the opportunity to appear before this Subcommittee to explain the importance of the role of independent power producers and to point out the potential obstacles to increased cogeneration in the electric power industry.

I am Dr. Donald E. Hirsch, Director of Technical Services, International Minerals & Chemical Corporation ("IMC"). I am appearing today on behalf of The Fertilizer Institute ("TFI"). TFI is the national association of the fertilizer industry whose membership accounts for over 95 percent of total United States fertilizer production. In partnership with our Nation's farmers, fertilizers from TFI's members contribute to our abundant supply of food and fiber. IMC is a member of TFI and has been in the forefront of developing cogeneration capacity in connection with its fertilizer operations.

Importance Of Cogeneration To The Fertilizer Industry

It has generally been recognized that the application of fertilizer by farmers accounts for over one-third of this Nation's food and fiber production. Cogeneration has the potential for making our domestic producers of each of the three primary plant nutrients -- nitrogen, phosphate and potash -- more efficient and cost effective and thereby strengthening the ability of the domestic fertilizer industry to compete with foreign suppliers.

A preliminary survey by TFI indicates that there are at least 13 cogeneration units operating in our industry and that at least five new ones are planned to become operational in the next 12 months. In addition, we believe that a substantial number of new cogeneration facilities in the fertilizer industry are under active study, but precise data on these potential projects is not possible due to the highly proprietary nature of this information.

Substantial cogeneration capacity has been constructed in connection with the production of phosphate fertilizers in Florida. For example, at IMC's New Wales facility located near Mulberry, Florida, where IMC produces phosphate fertilizer ingredients, our cogeneration facility includes two turbine generator sets with a combined nameplate capability of about 65 megawatts.

While phosphate operations have been the recent focus of cogeneration in the fertilizer industry, there are also cogeneration facilities utilized in connection with the production of potash and the recovery of sulfur, a key ingredient for many fertilizers.

Moreover, the nitrogen fertilizer industry offers a very substantial potential for new cogeneration projects. Fertilizer manufacturers utilize large quantities of natural gas as a feedstock and energy source in the production of nitrogen products. The addition of cogeneration results in more efficient use of this energy. Cogeneration projects may assist some manufacturers to continue to operate their plants in the face of increasing foreign imports of nitrogen fertilizers. In addition, new projects are being considered in view of the projected sharp rise in electric rates for many parts of the United States, including Louisiana where there are a large number of nitrogen fertilizer facilities.

The availability of cogeneration has two important advantages to the fertilizer industry. First, cogeneration allows our domestic fertilizer producers to become more efficient. By the combined production of power and useful thermal energy, cogeneration requires less total energy than the separate production of electricity and process steam. For a particular fertilizer manufacturer, cogeneration means a reduction in operating costs. A cogeneration project will not be undertaken unless the total operating costs of a fertilizer manufacturing facility are projected to be lower. Because domestic producers of fertilizers for each of the three primary plant nutrients must compete against foreign producers on the world market, it is essential that domestic fertilizer producers be as efficient as possible. Thus, lower operating costs through cogeneration will contribute to the maintenance of a domestic fertilizer industry in the face of foreign imports and allow U.S. fertilizer producers to compete for world markets.

A second major benefit of cogeneration to fertilizer manufacturers is that the potential option of self-generated power provides an alternative to purchasing electricity from a utility. Rather than being forced to accept unending rate increases, a fertilizer manufacturer can elect to generate its own power. This freedom of choice through the potential for self-generated power imposes a market restraint on electric utilities. The lesson to be learned from the cogeneration experience is that there is no guaranteed market for electricity, even under the "monopoly" provided to a regulated utility, and that to sell their power, the electric industry must offer cost effective rates. This discipline of what amounts to a type of competition will deter wasteful investment in over capacity built on the assumption that ratepayers will provide electric utilities a guaranteed rate of return on their investment.

The General Benefits Of Cogeneration

Not only does cogeneration benefit fertilizer manufacturers, but it also has general benefits for the entire economy. First, there is a net saving of energy through cogeneration so that energy conservation is furthered. Second, most cogeneration in the fertilizer industry utilizes energy that would otherwise be wasted. For example, in the phosphate fertilizer industry, the heat generated in the production of sulfuric acid from sulfur is utilized to produce steam that is used to first produce electricity and then for process heating. Another example is a member company, Freeport McMoRan, which could double its current electric output if the price of power would justify capital expenditures or wheeling were available to its sulfur terminal. Thus, not only are, fossil fuels conserved but also the environment is spared the products of the combustion of oil or coal. Third, the installation of cogeneration facilities serves to avoid, or at least delay, the future investment in expensive and less efficient utility generation facilities. It is the construction of major generating facilities with their ever increasing capital costs that has been the source of most of the rate increases in recent years. Fourth, a more efficient and cost effective domestic fertilizer industry provides the Nation's farmers with a secure source of fertilizer and thereby lessens our potential dependence on foreign imports.

Obstacles To Increased Cogeneration

We believe that cogeneration by industry is an appropriate type of competition for the electric power industry. Our chief concern is that the Public Utility Regulatory Policies Act of 1978 ("PURPA") will be amended in a manner which will discourage the use of current cogeneration facilities and the development of new facilities. We continue to hear reports that opponents of cogeneration intend to launch a major campaign in the next year to modify the existing law.

As you know, PURPA has been essential to the development of cogeneration. While a few cogeneration projects took place in the fertilizer industry prior to PURPA, much of our industry's capacity has been developed since 1978. Federal and state regulations issued under PURPA require utilities to interconnect to provide backup power on a non-discriminatory basis and to purchase excess power from cogenerators at the avoided cost rate. PURPA has also removed cogenerators from most federal and state utility regulation. Any serious discussion of changing these fundamental provisions of the PURPA regulations will certainly discourage the development of new cogeneration capacity. Thus, we need a firm statement from this Subcommittee that Congress intends to maintain its commitment to cogeneration.

There is one addition to PURPA that could significantly contribute to better utilization of existing facilities, promote the development of new projects and extend this appropriate type of competition for the power industry. Such an amendment would allow wheeling of cogenerated power to facilities owned by a cogenerator (self-service wheeling) and to plant sites which are immediately adjacent to cogeneration facilities.

For example, IMC would like to wheel power from its New Wales facility to its Kingsford mine which is less than three miles away. Although it is completely practical for us to build our own power line from New Wales to Kingsford, this would be a wasteful duplication of the existing utility line and, furthermore, would deprive the utility of a wheeling fee. However, the regulatory situation is very uncertain as a result of rulings by the Federal Energy Regulatory Commission and the Florida Public Service Commission. While the Florida Public Service Commission has recently issued regulations that might permit self-service wheeling, it is unclear at this time whether we will be able to move power to our own facilities in Florida in the face of expected opposition from utilities. Therefore, should this Subcommittee consider amendments to PURPA, we request that you consider legislation which would provide cogenerators with the option of moving power to their own facilities.

In addition, wheeling of cogenerated power should also be permitted to plant sites which are immediately adjacent to the site of a cogenerator. Often, fertilizer manufacturers are located adjacent to other industries, such as petrochemical manufacturers. One manufacturer will find themselves with excess heat from which they can manufacture more electricity than is required at the site and the adjacent manufacturer has a need for electricity but has no excess heat. If these two industries were permitted to enter into a cooperative effort, both could be benefitted. The public would also benefit as a result of conservation, further environmental improvement and the delay of the need for building additional expensive utility generation. Due to many recent acquisitions and divestitures, some plant sites now have several owners for specific parts of the plant. These sites have common facilities which are provided to the various owners through service agreements. Sharing of electricity under these circumstances is another example of a cooperative effort that should be allowed. The concept of an industrial park is a logical extension of this type of cooperative effort. A central facility generating both heat and electricity for the utilization of the park members would provide the efficiency and low cost that is so badly needed today. This kind of healthy freedom of choice would benefit both industry and the general public.

Conclusion

The experience of the last decade has demonstrated that regulation has not been effective in ensuring that electric power is provided at reasonable rates. We believe that cogeneration provides a freedom of choice which is appropriate for the electric power market.

The purpose of our testimony this morning is not to point the finger at any particular group, but instead to apprise this Subcommittee of the existing and potential benefit of cogeneration in the fertilizer industry. Again, we emphasize that the important protections provided cogeneration by PURPA not be watered down and that PURPA be strengthened by allowing the wheeling of cogenerated power to plants owned by cogenerators and to plant sites immediately adjacent to the facilities of the cogenerator.

Independent Power Producers Council
P.O. Box 693
Boise, ID 83707

JUN 5 1986

May 28, 1986

Honorable James A. McClure
Chairman of Energy and
Natural Resources Committee
United States Senate
Washington, D.C. 20510

Attention: Gerry Hardy

Re: Comments on Public Utility Regulatory Policies Act of 1978

Dear Senator McClure:

These comments are submitted in conjunction with the hearing scheduled June 3 and 5 to consider the Public Utility Regulatory Policies Act of 1978 ("PURPA") to be included in the record of the proceedings. The Independent Power Producers Council ("IPPC") is an Idaho non-profit corporation organized for the purposes of advancing small power producer's interests in Idaho. The IPPC is geographically located primarily in the service area of Idaho Power Company. Its membership consists of Idaho's largest corporations and numerous ranchers, farmers and small businessmen.

Competition and PURPA have experienced a very difficult road to travel in Idaho since the Idaho Public Utilities Commission implemented PURPA starting in 1981.

The Idaho Public Utilities Commission has been required to hear numerous complaints against Idaho Power by developers seeking to enter the electrical generation business as competitors of Idaho Power. In one memorable Idaho Public Utilities Commission order requiring Idaho Power to sign a contract with a small power producer, the Idaho Public Utilities Commission stated in part:

> "In short, Idaho Power Company now refuses to honor the rates that are approved and on file at the Commission as even the basis for commencing negotiations with cogenerators or

> small power producers. Such a defiance of final ratemaking orders is unparalleled in the experience of this Commission. We remind Idaho Power Company that it is a regulated utility and that its announced Company policy in this matter makes it an outlaw--in that word's precise meaning of operating outside the law. (Emphasis Added) Koyle v. Idaho Power Company, Case No. U-1006-206.

The opinion above capsulizes Idaho Power's efforts and numerous other utility's efforts throughout the nation to deny entry in the electrical generation business to qualified facilities.

The IPPC believes that Idaho Power's efforts to deny entry into the electrical generation business can be explained by reviewing the costs of an electrical generation plant Idaho Power has recently built, to the rates available to Idaho Power's competitors. In Case U-1006-265 at the Idaho Public Utilities Commission Idaho Power is presently requesting that the Commission allow into rate base a coal fired plant with a cost to ratepayers of between 6.5¢/kwh to 7¢/kwh. In addition, Idaho Power has simultaneously requested that its most recent hydroelectric plant at Cascade, Idaho be allowed into rate base at 8.5¢/kwh to 9.0¢/kwh. The costs of these facilities can be verified by contacting Michael S. Gilmore, Idaho Public Utilities Commission. The above rates are subject to unlimited escalation for which the ratepayer will be fully charged.

The rate for qualified facilities under PURPA in the State of Idaho is presently 4.4¢/kwh during a thirty-five (35) year period. In addition, a qualified facility will receive over the thirty-five (35) year life of its contract a very small and limited escalation for inflation.

In comparing the above rates, the advantages to Idaho Power's ratepayers is abundantly obvious. The cheaper source of firm, long term power is clearly Idaho Power's competitors and yet Idaho Power continues in the courts, at the Federal Energy Regulatory Commission and at the Idaho Public Utilities Commission to frustrate competitors seeking to develop projects under PURPA. In one case alone, Idaho Power Company has been engaged since July of 1982 in continuous litigation in the Idaho Supreme Court apparently seeking to destroy a competitor and the small power industry, (See Afton v. Idaho Power Company).

The IPPC believes that Idaho Power and other regulated utilities have and will continue to resist competition made possible by PURPA. The above facts clearly indicate that cheaper electrical power is generated from qualified facilities in Idaho. The situation in Idaho typifies the cost discrepancy between qualified facilities and new mammoth coal or nuclear plants. Recently, numerous states such as Connecticut, Massachusetts, New York, Maine, Vermont and New Hampshire have recognized the advantages of attracting power resources from qualified facilities.

Regulated utilities traditionally purchase the most expensive plant and resources which can be fully passed on to the ratepayers with the greatest return based on the cost (investment) for purchasing the most expensive generating resources. Without the competition from PURPA, there simply is no economic incentive in the utility industry to build the most cost effective and most efficient generation resources. The present system rewards shareholders and management of regulated utilities by building the most expensive units to obtain the highest returns on such investments.

If PURPA is given a chance in the state and federal agencies, the IPPC believes that regulated utilities and State Commissions will, over time understand that independent companies can provide ratepayers substantially lower cost power without the economic risks of building a large plant. Regulated public utilities should concentrate their efforts on distribution of electrical energy at the lowest cost possible. A regulated utility, by owning the distribution system, does not have a monopoly or legal right to be the sole source of generation capacity when qualified facilities can be more economical in generating electrical power.

If the United States wants to rid itself of environmental problems such as acid rain from huge, new coal generating plants and increasing exposure to nuclear risk, then PURPA offers abundant resources at advantageous prices through qualified facilities. California early on implemented a PURPA program which has resulted in abundant new resources from environmentally benign hydro and waste projects. As the resources from qualified facilities have materialized, the price of electrical generation has declined in California and many other states.

PURPA's competition then, is the answer to lowest cost electrical generation.

Very truly yours,

Owen H. Orndorff
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General Counsel

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STATEMENT
OF
GLENN H. LOVIN
REPRESENTING THE
INTERNATIONAL COGENERATION SOCIETY
BEFORE THE SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
ON
THE IMPLEMENTATION OF THE PUBLIC UTILITY
REGUALTORY POLICIES ACT

Statement for the Record

The International Cogeneration Society (ICS) is pleased to submit the views of its members concerning the implementation of the Public Utility Regulatory Policies Act of 1978. The International Cogeneration Society represents a broad interest in the prudent development of cogeneration energy systems.

ICS would like to respond, only as it concerns cogeneration, to the three basic concerns of the Senate Energy and Natural Resources Committee: First, to what extent have the basic goals of PURPA been achieved? Second, what new problems have been created, particularly those involving the issue of fairness to electric utility ratepayers and third, to what extent are those problems self-correcting; that is, have the States displayed an ability to respond to changing circumstances and modify their requirements accordingly, thus perhaps obviating the need for corrective legislation at the Federal level.

Have the basic goals of PURPA been achieved? If the goals have been achieved for cogeneration they have not been fulfilled. The PURPA legislation did remove many of the barriers suppressing the implementation of cogeneration. Based on the current growth, in an era when we have put the energy crisis behind us, it appears that cogeneration is a maturing technology. The record-setting number of plants being ordered today, without many of the benefits provided in the tax programs enacted in the early 1970's, indicate the economies of cogeneration as a viable alternative to purchasing high-cost electricity from local utilities.

Has the development of cogeneration been fair to utility ratepayers? That depends to a great extent on how the program is implemented in local utility service areas. The basis for the Oversight Hearing on Implementation of the Public Utility Regulatory Policies Act of 1978 is a concern primarily for the four utilities operating in the Pacific northwest: Idaho Power Company, Washington Water Power, Utah Power & Light and Pacific Power & Light Company.

A close examination of these four utility companies, and where PURPA power is produced, reveals some startling facts! Idaho Power has 49 PURPA projects on their system. Five are cogeneration projects: One burns methane gas from a sewage plant, three burn waste wood and the other burns waste from and industrial process in a potato factory. Washington Water Power Company has 11 PURPA projects, two are cogeneration plants and both burn a waste product for fuel. Utah Power & Light Co. has 13 PURPA projects, 12 hydro and one windmill. Pacific Power & Light Co. has one project in that region...it's a hydropower project. The amount of cogenerated power purchased by the four companies in that region is less than one half of one percent. It is unfortunate that cogeneration plants, achieving high efficiencies, burning renewable fuels and waste products, should "go on trial" because hydropower is flooding the Northwest.

It is difficult to understand how anyone, including the United States Congress, could be concerned that the United States is rapidly developing its abundant supply of water resources and utilizing renewable and waste products to generate electricity and steam.

The fairness question should be examined more closely as to why the utility, with surplus capacity, does not retire inefficient older plants and take them out of the rate base. The environmental benefits of cogeneration offer substantial savings that benefit utility ratepayers. The wheeling of power from a surplus area to an area where capacity is needed could generate revenue for the wheeling company and same millions for the utility needing capacity. The avoided-cost formulas within PURPA are designed to protect utility ratepayers.

Natural gas-fired cogenerators, in other parts of the country, producing both steam and electricity make better use of finite resources than nuclear power plants, 85 to 95% complete, converted to natural gas or coal. Cogeneration capacity in operation and the potential for future development has enabled some utilities to avoid or delay base load central station plants. The savings, instead of being used for rate reductions, are being invested in purchasing banks, insurance companies, cable televison systems, coal mines, barges, office buildings, real estate, transportation systems and other income producing properties. Some utilities are now approaching monopoly control of commerce within the state.

The states have the ability and are responding to changing circumstances as it concerns the implementation of PURPA. If the requirements that local utilities purchase cogenerated power are of great concern to the Committee, especially in areas of surplus capacity, it may be worthwhile to consider an open market for the power. It may be wheeled to the highest bidder. Let the free market set the price and the amount of cogeneration capacity for the future.

UNITED STATES OF AMERICA
BEFORE THE SENATE
COMMITTEE ON ENERGY
AND NATURAL RESOURCES

Hearings on)
The Public Utility Regulatory Policy Act of 1978)

COMMENTS OF THE NATIONAL ASSOCIATION OF ENERGY SERVICE COMPANIES ON IMPLEMENTATION OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

The National Association of Energy Service Companies ("NAESCO"), pursuant to the request from the Staff of the Senate Committee on Energy and Natural Resources, hereby submits comments to assist the Committee in evaluating the effectiveness of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). NAESCO's comments also address current regulation by the Federal Energy Regulatory Commission ("FERC") and actions by state public utility commissions ("PUC's") to implement PURPA. Although NAESCO did not present oral testimony during the Committee's hearings on PURPA, it wishes to state its strong support, as set forth more fully below, for continuing the PURPA statutory scheme unchanged.

I. IDENTIFICATION OF NAESCO AND ITS INTERESTS

NAESCO is a District of Columbia nonprofit trade association with over 130 members nationwide involved in all aspects of the energy service industry. NAESCO's members include wholly-owned subsidiaries of large utilities which are participating in PURPA projects, energy contractors, energy management companies, large manufacturers and suppliers of energy-related equipment and services, engineering firms and approximately 30 state energy offices. A list of NAESCO's current members is attached hereto as Appendix A. NAESCO represents its private and public sector members in matters relating to the development, ownership, construction, financing and management of energy service projects, including cogeneration and small power production projects eligible for qualifying facility ("QF") status under PURPA (hereinafter referred to as "independent power projects" or the "independent power industry"). Many of NAESCO's members are actively involved in constructing, owning and operating independent power projects and in assuming the risks and burdens of such construction, ownership and operation.

II. LEGAL STATEMENT OF POSITION

A. There Is No Need To Change PURPA Today

During the two days of PURPA hearings held by the Committee, the testimony presented almost exclusively supported continuing PURPA in its present form. Witnesses before the Committee conclusively cited PURPA as having the flexibility to achieve the statutory objectives stated by Congress in 1978 when the law was passed. The witnesses indicated that PURPA's encouragement of small, dispersed, low-cost independent power projects created an important, viable and reliable alternative to meeting this nation's electric generating needs. Moreover, contrary to some concerns expressed by the Committee, the witnesses confirmed that PURPA does not require utilities that do not need power (those utilities that have excess capacity) to provide a capacity payment to independent power producers when purchasing QF power. Even utility representatives testifying before the Committee approved of PURPA and recommended that the statute need not be changed.[1] Accordingly, the consensus from the hearings was that PURPA is presently working as intended, and that states that need disbursed, low-cost QF power are obtaining it while states that have no need for such power are not.[2]

1. Effectiveness of PURPA

No statute involving a national regulatory scheme can perfectly balance the interests of all parties affected by the statute with precision; and PURPA is no exception. However, NAESCO believes that PURPA is doing a much better job of achieving this balance than anyone could have anticipated. This is particularly the case in light of the changing nature of oil prices since 1978.

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[1] For example, D.E. Simmons, Group Vice President of Power Operations for Houston Lighting & Power Company, appearing on behalf of the Edison Electric Institute, testified that, if effectively implemented, PURPA would contribute to the development of alternative energy and would ultimately benefit electric consumers. Mr. Simmons' testimony suggested certain regulatory improvements to PURPA implementation which he believed could better accomplish the goals of PURPA, but did not suggest that there was a need to substantially change the statute. ("Testimony of D.E. Simmons, Houston Lighting & Power Company, on behalf of the Edison Electric Institute" at p.8.)

[2] The one exception may be the state of Idaho, which is unique in the fact that it has the lowest priced utility-generated power in the country. Notwithstanding this, Perry Swisher, President of the Idaho PUC, testified that the presence of the independent power industry was highly beneficial to ratepayers in Idaho and the Pacific Northwest and to the area's economically recovering agricultural, mining and timber industries. ("Prepared Remarks of Perry Swisher" at p. 2.)

In return for the benefits of PURPA, developers, owners and operators of independent power projects, including NAESCO's members, have had to assume much greater risks than electric utilities have traditionally had to assume in building generation capacity. Specifically, an independent power producer has no traditional rate base protection and no means to recoup its costs if its project does not go on-line. On the other hand, in return for being required to purchase QF power, electric utilities have been able to avoid the need to construct new high-cost (particularly nuclear) capacity and have been relieved of much of the significant cost over-runs they have experienced in the past. Thus, both sides have effectively benefited from PURPA implementation. In addition, the effective balancing of independent power producer and utility interests under PURPA has resulted in more cost-efficient construction and operation of small, dispersed power facilities and in less risk to ratepayers from large utility generating project cost overruns.

Since 1978, however, implementation of PURPA at both federal and state levels has been subjected to numerous uncertainties which have made it difficult for the nation to realize the full extent of PURPA's intended benefits. These events have also made it difficult for the independent power industry to obtain PURPA's benefits in many areas of the country.

- FERC regulations implementing PURPA were not promulgated until two years after PURPA was passed, thereby delaying PURPA implementation at the state level.
- Both PURPA and its implementing regulations were challenged for five years in the federal courts, and it was not until 1983 that Supreme Court decisions finally removed the legal cloud over the PURPA implementing scheme. In addition, state laws and policies implementing PURPA have been subject to numerous challenges in the state courts.
- After 1983, federal and state regulators faced the challenge of implementing PURPA during a period of increased energy conservation and dramatic swings in energy costs.
- The implementation of PURPA has also occurred during a period of changing tax policies and incentives which have affected the development of the independent power industry.

In light of these uncertainties, NAESCO believes that the independent power industry has not yet had a full and fair chance to develop. Because the legal impediments to PURPA were only cleared away within the last two years, most states are just now beginning to see the start of independent power construction within their borders.[3] When states such as California and Texas (which account for over 80% of planned or constructed independent power projects under PURPA) are excluded, it is clear that the majority of states and their ratepayers have not yet experienced the benefits of PURPA. This situation may soon change, however

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[3] For example, after eight years of PURPA implementation in New Jersey, one of the country's largest and most industrial states, only five independent power projects have ben constructed and are presently operating.

(and NAESCO is optimistic that it will), as states like New Jersey, Connecticut, Massachusetts and Florida recognize the need for QF power and adjust their avoided cost rates accordingly.

Notwithstanding the uncertainties noted above, however, evidence presented to the Committee indicates that PURPA, as presently implemented by the FERC and by state PUC's in California and Texas, is proving to be an effective statutory mechanism for encouraging independent power development in the manner contemplated by Congress when the law was passed.

- Between 1980 and March 31, 1986, the FERC received approximately 2700 requests for QF status from potential independent power producers, representing nearly 40,000 MW of capacity. FERC is currently conducting a comprehensive survey of the status of the projects which have filed for QF status to determine how many projects are constructed and/or operating. (Statement of Lawrence R. Anderson, Director of the Office of Electric Power Regulation, FERC" at pp. 1-2, 4.)
- It is estimated that currently over one-half of the Fortune 500 companies are producing independent power or engaging in the provision of independent power production equipment or services. ("Written Comments of the Cogeneration Coalition of America, Inc., on Implementation of PURPA and Development of Cogeneration and Small Power Production Facilities" at p. 11.)
- The alternative power market currently represents 7% of total electricity produced in the United States and is expected to increase to over 10% by 1989 and to 15% by 1995. (*Id*. at p. 9 and Attachment 4.)

In light of these favorable statistics, but keeping in mind the uncertainties noted above, NAESCO believes that any change in PURPA, no matter how minor, would thwart the potential for states, other than California and Texas, to fully realize PURPA's intended objectives. Moreover, as previously stated, no evidence exists to indicate that there is a need to change PURPA today. Instead, NAESCO urges the Committee to clearly indicate its desire to provide federal and state regulators additional time, at least through 1990, to implement PURPA in its present form. Such a statement from the Committee, in addition to the adoption of the additional recommendations made below, would help remove the state of uncertainty which up until now has been the major stumbling block to effective PURPA implementation and full realization of PURPA benefits.

B. State Implementation of PURPA

PURPA and FERC regulations also provide an appropriate mechanism for allowing individual states the flexibility to promulgate state regulations to implement PURPA in accordance with their own specific electric utility load demand forecasts and supply planning analyses. Individual states have very different capacity conditions and resource mixes and, therefore, have devised very different approaches to developing their independent power industry.

- For example, California, a state which historically has had great capacity needs and which has relied heavily on expensive imported oil and natural gas-fired generation, has aggressively implemented PURPA by developing a range of standard offer avoided cost contracts for a variety of types of independent power projects and project reliability levels and a number of other procedural mechanisms to foster such development. California's approach to PURPA is described more fully in the testimony of Ducan Wise of the California Public Utilities Commission.

- Similarly, as fully described by Dennis Thomas of the Texas Public Utility Commission, Texas, a state which has experienced a substantial growth of independent power in its petrochemical and refining industries, has adopted a market-based approach to PURPA implementation to determine the appropriate types and amounts of independent power production in the state.

- In contrast, a state such as Louisiana or states in areas such as the Pacific Northwest which are capacity sufficient and which have access to low-cost fuel sources and baseload electric plants have been free to implement PURPA on a much smaller scale based on their lack of need for independent power production.

NAESCO believes that one of the keys to continuing PURPA's success is the continued ability of each state to flexibly evaluate, and constantly re-evaluate, the state's avoided costs and other PURPA rates. This evaluation should continue to be made by the states in accordance with their own changing economic conditions, projected demand for energy efficiency and independent power projects and other electric generation and capacity needs.

C. Implementation Issues On Which Additional FERC Guidance Is Needed

Notwithstanding the success of current implementation under PURPA on the federal level and in a few states, notably California and Texas, many states have taken approaches to implementing PURPA which unnecessarily hinder independent power development, often without the specific intent of doing so. NAESCO believes states should implement PURPA in order to regulate the amount of QF power within each state by establishing a true avoided cost rate for such power. Unfortunately, certain

PURPA implementing actions taken by some states have the potential for (1) impeding the continued efficiency of independent power development; (2) raising project costs due to the continuing uncertainty of state implementation approaches; (3) increasing the difficulty of obtaining project financing; and (4) threatening the continued operation of existing independent power projects which are currently helping to meet this nation's power needs. To prevent states from thwarting PURPA's intended statutory objectives, which, as discussed above, should not be changed, NAESCO believes FERC should address the following issues in a policy statement, notice of inquiry or notice of proposed rulemaking to supplement the current PURPA regulations:

1. States should be required to offer standard offer contracts for the purchase of QF power.
2. States should be prevented from using contract reopener provisions in executed power purchase agreements.
3. States should require utilities to provide back-up power to independent power users at just and reasonable cost-based rates.
4. States should ensure that independent power producers are accorded reasonable access to utility transmission facilities at reasonable wheeling rates.

These issues are discussed more fully below.

1. Standard Offer Contracts

FERC should recommend, through a policy statement, that states establish a variety of standard offer contracts to implement PURPA and meet the needs of various independent power producers.

- Standard offer contracts create a more even bargaining position between utilities and independent power producers, so that utilities, which view independent power producers as low-priced competitors (rather than allies in the battle to achieve lower rates) cannot deter independent power development by insisting on unreasonable power purchase contract terms which destroy the economic viability of independent power projects.

- Standard offers should be complete contracts analogous to utility tariffs for electric sales, ranging from as-available to long-term power contracts, which would be available upon request by the independent power producer.

- FERC should establish guidelines for states to calculate avoided capacity costs under standard offer contracts based on the construction of the next hypothetical future plant to be added to each utility's resource base in the state.

- FERC should encourage states to permit the use of levelized payments in standard offer contracts in appropriate circumstances to provide protection for independent power producers against the risk that avoided costs will decline in the short-run. These levelized payment standard offer contracts should also include off-setting price benefits to ratepayers during the latter years of the contract.

- Periodic revision of price terms should be undertaken and the standard offers modified as needed. However, such adjustments should be made on a prospective basis only.

- Appropriate safeguards, such as reasonable project milestones, should be incorporated into standard offer contracts to ensure that projects under contract are actually constructed.

2. Contract Reopeners

FERC should provide clarification that, under PURPA, states cannot permit PUC's to annually adjust the price terms in executed power purchase agreements. Such "reopener clauses" almost completely destroy the financeability of independent power projects, regardless of their otherwise economic value and societal merit. Once a contract price is set, the price term cannot be subject to change by a regulatory body. States which allow such contract price changes effectively destroy the main purpose behind PURPA, the creation of an independent power industry whose members are willing to assume, in return for a guaranteed price for their power, project development and operation risks without the assurance of a rate base return. A more viable alternative would be for FERC to recommend that state PUC's be given a 60 day period prior to execution of a power purchase agreement to approve or reject contract terms and conditions. Once a power purchase contract is approved, it should not be subject to being reopened by future PUC's.

3. Back-Up Power

FERC should reverse its August 1985 decision in Alcon (Puerto Rico), Inc., 32 FERC ¶61,247 (1985), which suggests that a consumer of QF power does not have the PURPA guaranteed right to receive back-up, standby or maintenance power from its utility if its independent power source is third-party owned and financed. The Alcon decision is currently pending rehearing. FERC should issue a generic policy statement requiring states to ensure the provision of such services to independent power users at just and reasonable cost-based rates.

- Denial of back-up power to a host facility on the ground that, for financing reasons, the host facility is a separate entity from the independent power project is contrary to the spirit and intent of PURPA.

Congress certainly contemplated the use of such financing techniques to encourage development of the independent power industry when it passed PURPA.

- o FERC's policy statement should encourage state review and implementation of new tariff provisions to govern the provision of back-up power. State implementation should include the removal of onerous tariff reliability provisions, unjust demand ratchet clauses and other disincentives associated with utility provision of back-up service.

The FERC policy statement should recognize that PURPA implementation must not be governed by the manner in which an independent power project is owned or financed and that FERC and the states must continue to implement PURPA so that its benefits continue to promote needed independent power projects.

4. Access to Transmission Service

FERC should act to encourage utilities to provide independent power producers with reasonable access to utility transmission facilities at reasonable wheeling rates and to encourage both the interstate and intrastate wheeling of cogenerated power.

- o Access to the transmission grid is essential to encourage and maintain the competition between utilities and independent power producers contemplated by PURPA. Independent power producers should be freely allowed to wheel their power to other utilities as well as to their own sites (so-called "self-service wheeling").

- FERC should recommend that states adopt a postage stamp rate for the wheeling of independent power and should provide guidelines for use by the states in determining the proper allocation of transmission costs to independent power producers as well as the other non-price terms of a transmission service agreement between a utility and an independent power producer.

D. Maintenance of PURPA's Benefits

The passage of PURPA in 1978 opened the utility generation field and the electric grid to competition. Continued implementation of PURPA in its present form is currently forcing traditional electric utilties to prove that they can produce power as cheaply and as efficiently as independent power producers. The attractiveness of PURPA's benefits for small, dispersed, privately-owned independent power projects, notwithstanding the risk of the loss of rate base protection, is evident by the fact that many traditional electric utilities are creating subsidiaries, many of whom are NAESCO members, to participate in the development, ownership and operation of such projects. Maintenance of the benefits currently provided to independent power producers under PURPA, subject to the continuing regulatory oversight of FERC as suggested herein, is the best way to insure the continuation of competition between independent power producers and utilities and to provide the least cost power to electric consumers.

E. Conclusion

During the course of two days of hearings on PURPA, the Committee received testimony from the independent power industry, utility representatives, members of state PUC's and the FERC. Not surprisingly, there was disagreement over a number of specific PURPA implementation issues. However, despite identifying a number of areas for improvement in PURPA implementation by FERC and state PUC's, the witnesses overwhelmingly supported the continuation of PURPA in its present form. NAESCO joins in this support and believes that it provides a clear indication to Congress and this Committee that PURPA has been an effective means for promoting energy conservation and low cost, dispersed independent power production which should not be changed.

Respectively submitted,

NATIONAL ASSOCIATION OF ENERGY
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By: George P. Sakellaris
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IMPLEMENTATION OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

Statement of Ralph Cavanagh
Senior Staff Attorney
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to the

Senate Committee on Energy and Natural Resources

June 5, 1986

NRDC Statement on the Public Utility Regulatory Policies Act

June 5, 1986

The Natural Resources Defense Council (NRDC) appreciates the Committee's invitation to present its views on the Public Utility Regulatory Policies Act (PURPA). NRDC is a national, nonprofit environmental organization with more than 62,000 members and contributors; its staff of attorneys and scientists has been active on electrical energy issues for more than fifteen years. We intend to supplement this brief statement with a more detailed analysis prior to the close of the record.

NRDC disagrees with those who are arguing today for a major overhaul of PURPA. Most current debate centers on the law's "avoided cost" provisions, which allow independent power producers to compete on equal terms with utility-owned power plants for ratepayers' investment dollars. The result, in some jurisdictions, has been a spectacular outpouring of competitors. In our view, this in no way weakens the case for paying independent producers at rates reflecting the costs of the power plants they are displacing. We concur in a conclusion that the U.S. Department of Energy recently published:

> Our review of PURPA implementation efforts indicates that the FERC and most state regulatory agencies have adopted a fairly reasonable approach to meeting the [avoided cost] requirements ... [M]any of the inefficiencies observed in this area are based on inappropriate computations of avoided costs rather than the statutory concept of avoided cost or the deliberate state effort to subsidize [independent producers] at the expense of ratepayers.

Emerging Policy Issues in PURPA Implementation vi-vii (March 1986).

What PURPA has yielded, in jurisdictions as diverse as California, Texas, and Maine, is a wide array of generally small-scale and privately financed alternatives to risky central station power plants. Our experience indicates that where such resources are successfully promoted, the trend for "avoided cost" payments by utilities has been one of steadily lower rates, even as the need for costly large-scale power plants has receded. These results should be more comforting than unsettling to utility executives traumatized by 115 nuclear plant cancellations and more than $20 billion in related expenditures since 1972.

PURPA certainly is not a flawless enactment. We have pointed out elsewhere that the legislation is too restrictive, in that efficiency improvements do not qualify for PURPA incentives. The Act speaks exclusively to the generation of electricity; its provisions can be searched in vain for any incentive to conserve the product. Ideally, utilities should evaluate central station plants on equal terms with both independent power production and efficiency improvements, with dollars flowing first to the cheapest and most reliable alternatives. Jurisdictions that take such comparisons seriously, like the Pacific Northwest, have found in conservation the largest, cheapest and least risky source of additional energy supply. It remains regrettable that PURPA is not structured to promote "least cost" decisions of this kind.

But that is an argument for broadening the reach of PURPA incentives, not cutting them back. We have supported the latter course only in the narrow context of hydropower development involving the construction of new dams, where environmental considerations counsel much greater caution than FERC has demonstrated. There, of course, we and others have argued strenuously that Congress never intended the hydropower boom that FERC unleashed in the early 1980s.

We hope for a solution of the hydropower problem in the Electric Consumers Protection Act of 1986, which should produce decisive changes in FERC's environmental policies. Meanwhile, this Committee should resist efforts to interrupt the state-by-state evolution of PURPA's competitive markets in electricity generation. PURPA is part of the cure for a utility sector that is only just emerging from some of the worst planning and investment fiascoes in U.S. history. We are aware of no substantial implementation problems that cannot be resolved within the current statutory framework.

SUPPLEMENTARY STATEMENT

OF

RALPH C. CAVANAGH

REPRESENTING THE

NATURAL RESOURCES DEFENSE COUNCIL

BEFORE THE SENATE COMMITTEE

ON

ENERGY AND NATURAL RESOURCES

REGARDING

THE IMPLEMENTATION OF THE
PUBLIC UTILITY REGULATORY POLICIES ACT

Submitted:

June 25, 1986

SUPPLEMENTARY STATEMENT ON THE IMPLEMENTATION OF THE PUBLIC UTILITY REGULATORY POLICIES ACT

Submitted to the Senate Committee on
Energy and Natural Resources
by Ralph Cavanagh, Senior Staff Attorney
on behalf of the Natural Resources Defense Council

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Introduction and Overview

This supplement expands upon a statement submitted to the Committee at its request on June 5, 1986, on behalf of the Natural Resources Defense Council (NRDC). NRDC is a national, nonprofit environmental organization with more than 62,000 members. Since its founding in 1970, NRDC's attorneys and scientists have made extensive contributions to national and regional debates on electrical energy policy. That work has produced numerous publications;[1] three major awards attest the organization's success in helping utilities minimize the economic and environmental costs of serving their customers.[2]

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[1] E.g., Least-Cost Planning Imperatives for Electric Utilities and Their Regulators, 10 Harvard Environmental Law Review 299 (1986) [cited below as "Least-Cost Planning"]; Preventing Wasted Light, The Construction Specifier 38 (Oct. 1984); Refrigerator Reform: Guidelines For Energy Gluttons, 86 Technology Review 36 (Feb./Mar. 1983); Electrical Energy Futures, 14 Environmental Law 133 (1983); Model Electric Power and Conservation Plan For the Pacific Northwest (1982).

This Committee has received extensive testimony on a key goal of the Public Utility Regulatory Policies Act of 1978 (PURPA): to ensure that no utility will expand its generating capacity without first offering independent entrepreneurs the opportunity to provide equivalent power at equal or less cost. That is the core of PURPA Section 210 and its implementing regulations. In at least one respect, there is agreement among groups as diverse as the Edison Electric Institute, the California Public Utilities Commission, the Electricity Consumers Resource Council, the Independent Energy Producers Forum and the Natural Resources Defense Council; on any reasonable list of priorities for Congressional action, PURPA revisions will not appear.[3] The basic charter remains sound, and the process of implementation is flexible enough to accommodate a dynamic electrical energy future.

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[2] These are the Bonneville Power Administration's Award for Exceptional Public Service (1986), the national Energy Conservation Coalition's Advocate of the Year Award (1985), and the Oregon Governor's Award for Outstanding Achievements in Energy Conservation (1984).

[3] See, e.g., Testimony of D.E. Simmons on behalf of the Edison Electric Institute, pp. 3 & 8 (June 3, 1986) (PURPA implementation problems "can and should be corrected through regulatory action, without need for legislative changes ... EEI believes that PURPA, if implemented correctly, can contribute to the efficient development of alternative energy and ultimately benefit consumers"); Testimony of Duncan Wyse on behalf of the California Public Utilities Commission, p. 2 (June 5, 1986) ("Both the PURPA statute and the subsequent implementation rules of the FERC are very sound"); Statement of the Electric Consumers Resource Council (ELCON), pp. 3,7 (June 5, 1986) ("PURPA has worked quite well ... PURPA should not be changed"); Accompanying Testimony of Jan Hamrin on behalf of the Independent Energy Producers Forum, p. iv (June 3, 1986) ("PURPA is working beautifully"); Statement of Ralph Cavanagh on behalf of the

This testimony will explore ways the states can make PURPA work better, as a vehicle for minimizing the costs of reliable electricity service in the decades ahead. Our major points may be summarized as follows:

1. PURPA has helped extricate U.S. utilities from some of the worst planning and investment mistakes in U.S. corporate history;

2. On at least some systems, independently-owned generators have proved that they can indefinitely eliminate the need for new utility-sponsored power plants;

3. Conservation opportunities deserve but often have not received an opportunity to compete on equal terms with independently-owned generators for utilities' investment dollars; and

4. States can optimize their investment in conservation and generating capacity through "least-cost" long-term resource plans, which meet specified criteria for managing and meeting system needs at the lowest possible life-cycle cost.

I. PURPA and The Fiscal Health of U.S. Utilities

PURPA's enactment in 1978 found much of the utility industry

Natural Resources Defense Council, p. 3 (June 5, 1986) ("[T]his Committee should resist efforts to interrupt the state-by-state evolution of PURPA's competitive markets in electricity generation.") All citations are to written testimony filed in conjunction with PURPA implementation hearings held by the Senate Committee on Energy and Natural Resources on June 3 and 5, 1986.

in acute financial distress. In the late 1970s, and for several years thereafter, financial analysts were dourly citing such indices of decay as the following:[4]

- "electric power companies are in the unsound position of paying out more in dividends than cash earnings;"
- "electric utility common stocks are trading at about 45% of their 1965 value and in dollars of constant purchasing power about 17% ... The industry is ... having trouble finding buyers for its common stock;"
- "[The] untenable position [of] the electric power industry ... clearly threatens its survival and ability to supply reliable electric power service."

Over the same period, an epidemic of costly power plant cancellations ravaged the industry: 75 coal-fired and 115 nuclear units were abandoned between 1972 and 1984, with utility losses on the nuclear units alone exceeding $20 billion dollars.[5]

From this carnage has recently emerged, with relatively little fanfare, a reinvigorated utility sector. By mid-1986, the trade press was writing of "the robust financial health of many 'cash cow' [utility] companies where internally generated cash is ballooning."[6] Electric utility stocks were keeping pace with or outperforming a strong bull market in industrial issues.[7] In the words of William McCollam, President of the Edison Electric Institute:

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[4] These excerpts are taken from a 1981 address by Paine, Webber Vice President Charles Benore to a conference sponsored by the California Public Utilities Commission. See California PUC, Energy Utilities: The Next Ten Years 20-27 (1981).

[5] The count of coal-fired units is taken from L. Brown, State of the World, 1986, at 100 (1986). The nuclear figures reflect (1) totals for the 1972-1982 period of 100 abandoned units and $10 billion in cancellation costs, reported in U.S. Department of Energy, Energy Information Admin., Nuclear Plant Cancellations: Causes, Costs and Consequences, at x (1983); and (2) the addition, in 1983 and 1984, of "fifteen more cancellations [that] added more than $11 billion to that figure." See Least-Cost Planning, note 1 above, at 302 n.11 and sources cited therein.

> We are [no longer] characterized ... by the need to survive, but rather by the need to assure that the industry, its shareholders and its ratepayers derive the fullest possible advantage from the gains that have been and are being made.[8]

While lower interest rates and reduced inflation undoubtedly contributed to "the gains that have been and are being made", in Mr. McCollam's phrase, much of the credit goes to sharply reduced investment in new power plants throughout the utility sector. Even before correcting for inflation, the sector's capital investment plans for 1986 show a 22% reduction from levels recorded in 1982.[9] Since the start of 1982, U.S. utilities have ordered only two new coal-fired power plants and no nuclear plants; *indeed*, the last nuclear order came in the year of PURPA's enactment (1978).[10] As recently as 1974, by contrast, 97 large-scale plants were ordered during one twelve-month period.[11] The promising fiscal indices cited above vindicate an earlier prediction of the U.S. General Accounting Office: "As construction programs are scaled back to accommodate a slower growth environment, [utilities'] financial condition should improve."[12] Utility after utility has learned not only that building large-scale power plants is an invitation to ruin, but also that not building them can be a prescription for prosperity.

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[6] Electrical World, at 49 (April 1986).

[7] See Electrical World, at 20 (May 1986) (during first ten weeks of 1986, electric utility stock shares kept pace with the Dow Jones industrials and outperformed the Standard & Poor's industrial index).

[8] See Electrical World, at 60 (April 1986) (brackets and ellipsis in original).

[9] See *id*. at 49.

[10] For a year-by-year tabulation of orders and cancellations since 1970, see L. Brown, note 5 above, at 100.

More is needed, of course, for sound electrical energy policy than simply a moratorium on utility-sponsored coal and nuclear power plants. PURPA's contribution, in part, is its redirection of entrepreneurial capital and ingenuity toward diversified, smaller-scale generating technologies. For example, the capacity of the average PURPA-inspired resource in California, Idaho and Maine is 13 Megawatts (MW), 2 MW, and 6 MW, respectively;[13] the average operating nuclear reactor had a capacity of 840 MW in January of 1986 (compared with 580 MW in

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[11] Id. (71 coal-fired and 26 nuclear units were ordered in 1974).

[12] U.S. General Accounting Office, Analysis of the Financial Health of the Electric Utility Industry 27 (June 11, 1984).

[13] See Prepared Testimony of Michael R. Peevey on behalf of the Southern California Edison Company, at I-5 (June 3, 1986) (listing 1214 "on-line plus committed" projects with a total nameplate capacity of 15,759 MW); Testimony of Logan Lanham on behalf of Idaho Power Company, at 3 (June 3, 1986) (132 projects; 312 MW); Central Maine Power Co., Cogeneration/Small Power Production: Pre-Decrement Through Subsequent Decrement (Feb.11, 1986) (78 projects; 437 MW).

1973).[14] And the sheer magnitude of the entrepreneurial response, in jurisdictions that have taken PURPA implementation seriously, is an eloquent answer to those who see in utilities' power plant cancellations the harbingers of electricity rationing. PURPA is part of the reason why the United States can now confidently discard large-scale coal and nuclear generating technologies from its options for expanding electricity supply, on grounds of both obsolescence and environmental protection.

It bears repeating that all this is good news for utility investors. The collapse of confidence in forecasts of electricity demand has made big power plants a dubious "bet-the-company" proposition.[15] Any utility's future, to the extent it can be seen at all through current planners' lenses, is embodied in forecasts that look like widening jaws; by the time the "high" and "low" scenarios for electricity needs reach the end of this century, they are separated by thousands or even tens of thousands of Megawatts. The last thing one would wish to insert between the forecast's gaping jaws is an indivisible large-scale, long-lead-time unit with most of its costs loaded into the construction phase. PURPA has helped to create a roster of more digestible, less risky alternatives.

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[14] See U.S. Department of Energy, Monthly Energy Review, Jan. 1986, at 83.

[15] The forecasting problem, which had become glaringly evident by the late 1970s, shows no sign of abating; an extensive empirical assessment, published in 1985, concluded that "direct observation shows little or no evidence that utility forecasting is improving over time." Huss, Can Electric Utilities Improve Their Forecast Accuracy? The Historical Perspective, Public Utilities Fortnightly, Dec. 26, 1985, at 37, 42.

II. PURPA's Impact on Utilities' Resource Planning

When PURPA was enacted, few expected independently-owned generators to seize a major share of the market for new power supplies. The Federal Energy Regulatory Commission initially foresaw 12,000 MW of PURPA-induced capacity by 1995, less than one-twentieth of then-prevailing estimates of the nation's need for new capacity.[16] Yet the conclusion that emerges powerfully from PURPA's first eight years is that wherever independent producers are offered long-term contracts at prices at or near the cost of a new utility-sponsored coal or nuclear plant, enough responses promptly emerge to displace all such plants indefinitely. In fact -- as attested in some of the testimony to this Committee -- too many offers often emerge, from the displacement perspective. Idaho, Montana and California were swamped, and had to cut their incentives back.[17] Anticipating that possibility, Maine and Masachusetts have instituted sophisticated systems for assigning priorities among applicants for long-term power supply contracts.[18]

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[16] See Pfeffer, Lindsay & Associates, Emerging Policy Issues in PURPA Implementation, at 3.12 (U.S. Department of Energy, March 1986).

[17] See Idaho Public Utilities Comm'n, Application of Idaho Power Co. For New Cogeneration/Small Power Production Rates, Case No. U-1006-248, Order No. 20350, Appendix (Mar. 28, 1986) (cutting avoided cost rates below 3 cents per kWh for 20-year contracts); Montana Public Service Comm'n, Investigation of Avoided Cost Rates, Docket No. 84.10.64, Order No. 5091c, at 77-78 (Mar. 7, 1986) (avoided cost rates will no longer be based on new baseload plants, since there are no new baseload plants to displace); California Public Utilities Comm'n, Decision 86-03-069 (Mar. 19, 1986) (temporarily suspending execution of capacity-displacement contracts with independent power producers, on grounds of market saturation).

In many states, of course, PURPA resources have never had a chance to prove their mettle; incentives have been held at starvation levels, often in response to local capacity surpluses.[19] But no jurisdiction of which we are aware has proceeded with new utility-sponsored capacity after giving independent producers a fair chance to compete for ratepayer dollars. That may be the most powerful lesson of the initial PURPA years, and it belies claims that only a strong upturn in utilities' capital budgets will spare the nation electricity shortages in the 1990s.

Yet we do not support a PURPA implementation strategy that simply pits independent producers against utilities' generators in a struggle for long-term supply contracts. A crucial competitor is missing from that scenario, and its omission could prove costly to both ratepayer and environmental interests. PURPA's goals cannot be achieved without full integration of cost-effective conservation into utilities' resource-acquisition plans.

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[18] See Putnam, Hayes & Bartlett, Maine's Cogeneration and Small Power Production: Matching Supply and Demand (August 1985) (independent producers compete for long-term contracts to provide portions of discrete blocks of capacity; "projects are ranked using an index system for the following variables: 1) price, 2) capacity, 3) endurance and 4) operational characteristics"); Massachusetts Department of Public Utilities, Proposed Regulations, D.P.U. 84-276-A (Feb. 3, 1986) (utilities must execute contracts of up to twenty years' duration with winning bidders for right to supply fixed blocks of capacity, ranked by criteria reflecting price and nonprice factors).

[19] Thus, the Electricity Consumers Resource Council appended to its testimony in this proceeding a 50-state survey of "avoided cost" rates under PURPA, compiled by Energy User News in 1985; a review of the data reveals that 23 states list one or more utilities whose maximum buy-back rate is less than three cents per kilowatt-hour.

III. Conservation as Energy Resource: PURPA's Greatest Omission

PURPA speaks exclusively to the generation of electricity; its provisions can be searched in vain for any incentive to conserve the product. Yet energy supply can be expanded either by producing more or wasting less, and the goal of planners should be to direct utility investment toward whatever methods for producing more *or* wasting less best reduce costs, uncertainty and risk.

Improvements in the efficiency of electricity use, if achieved in large quantities on a predictable schedule, constitute an energy resource. For purposes of meeting new system needs for power, a kilowatt-hour or kilowatt preserved from waste is indistinguishable from a kilowatt-hour or kilowatt delivered to consumers by a new power plant. Conservation options should be evaluated, then, as potential sources of supply, with a claim on utility investment dollars superior to that of more costly resources. In addition, conservation offers an alternative to new power plants as a means of extending some regions' current electricity surpluses, allowing long-term exports to capacity-strained and/or oil-dependent areas.[20]

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[20] The "conservation-for-export" concept is developed in Least-Cost Planning, note 1 above, at 315, 317 & 321.

Viewed as an energy resource, conservation has significant advantages when compared with either independently-owned or utility-sponsored power plants. Declining real energy prices in the postwar decades left a predictable legacy of inefficient electricity-consuming devices, which can be upgraded through programs that combine short lead-times, modest scale, and wide dispersal. The new conservation resources are added in small increments, not indivisible multi-Megawatt (or thousand-Megawatt) packages. Costs are incurred primarily during an installation phase of days or weeks, and are not subject to the unanticipated mid-construction escalation that has frequently shattered cost estimates for decade-or-more coal and nuclear projects.

Many PURPA generators enjoy comparable, albeit less pronounced, advantages over utility-sponsored competitors. But there are two conservation-linked claims that generators cannot make. First, conservation potential tracks the business cycle in a uniquely favorable way: rapid growth in demand is a function of rapid growth in the instrumentalities of consumption, and correspondingly rapid growth in opportunities to improve efficiency. The conservation resource automatically gets bigger as the need for it increases. In general, there is no such inherent congruence between power plant construction and the evolving needs at which such plants are targeted.[21]

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[21] Cogeneration also is arguably a resource that "gets bigger as the need for it increases"; an expanding industrial sector brings with it expanded cogeneration opportunities.

A second conservation dividend takes the form of reductions in costly uncertainty about future demand. The typical utility forecast is beset with indeterminacy because of its emphasis upon changeable trends in personal income, economic growth, employment, appliance saturation, fuel prices, and consumer sensitivity to rate increases. For purposes of determining energy consumption, however, these variables are much less important than the average efficiencies of the devices that actually use electricity. By working to improve those efficiencies on a determinate schedule, utilities can reduce the significance -- from the standpoint of ultimate energy needs -- of fluctuations in economic and behaviorial trends. For example, if regulatory and investment policies can fix the average needs of new houses, appliances and commercial floorspace at levels far below those typical of the current stock, then errors in predicting the absolute number of new houses, appliances and so on, become much less damaging.

In sharp contrast, power plants do nothing to reduce uncertainty about future demand; indeed, they may actually increase it: "The protracted installation of 500 to 1200 MW on a single site injects a major new element of volatility into electric rates, which are a key variable in long-range forecasts."[22]

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[22] See Cavanagh, Electrical Energy Futures, 14 Environmental Law 133, 155 (1983) (citing sources and examples.)

Accompanying states' increasing understanding of conservation's generic advantages are increasingly rigorous projections of its potential contribution to utility systems. Some of the figures form an instructive contrast to PURPA-related estimates presented to this Committee. Thus, even as a Texas witness cites prospects for up to 7300 more Megawatts of cogeneration, the state's Center for Energy Studies has identified almost 13,000 MW of cost-effective conservation in Texas buildings.[23] California witnesses look ahead to the possibility of more than 12,000 MW of additional PURPA resources, but California regulators and utilities have already cut more than 13,600 MW from projected peak needs for the year 2004, by adopting numerous regulatory and incentive programs to conserve electricity.[24]

In sum, even as they put PURPA to work, states should also be making provision for developing their conservation resources. And since no jurisdiction has infinite needs for new power supply, the two functions merit close coordination. We conclude with a proposal for ensuring that they get it.

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[23] Compare Testimony by Dennis Thomas on behalf of Public Utility Commission of Texas, at 4 (June 5, 1986) (PURPA projections) with University of Texas at Austin, Center For Energy Studies, Technical Potential for Electrical Energy Conservation and Peak Demand Reduction in Texas Buildings xxii (Feb. 1986) (conservation resources).

[24] Compare Testimony of Michael R. Peevey, note 13 above, at I-5 (PURPA projections) with California Energy Commission, The 1985 California Electricity Report, at 17 (May 1985) (conservation resources).

IV. Getting More Out of PURPA: Toward Least-Cost Resource Planning

States do not need a new and improved PURPA in order to realize the goals outlined in the previous section. The current version will suffice, provided that states apply it in the context of what has elsewhere been termed "least-cost resource planning." Such techniques, which have been used most extensively in the Pacific Northwest, ensure that utilities do not invest in power plants -- independently-owned or otherwise -- until they have first exhausted all less expensive conservation. That goal is entirely consistent with PURPA, but it cannot be secured without significant changes in most utilities' resource acquisition strategies. The necessary actions involve both utilities and their regulators, and have been described exhaustively elsewhere.[25] Key elements include:

(1) A long-range high- and low-case forecast of the system's electricity needs, tied as closely as possible to its existing and anticipated "end uses" of electricity (i.e., building shells, appliances, industrial processes);

(2) A comprehensive assessment of opportunities for improving the efficiency of those end uses, based on the state-of-the-art (existing and anticipated) for delivering equivalent service at the lowest possible energy consumption;

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[25] See Least-Cost Planning, note 1 above; Northwest Power Planning Council, Northwest Conservation and Electric Power Plan (1986); and sources cited in note 29 infra.

(3) A determination of how much of this unexploited "conservation resource" is less costly per kilowatt and kilowatt-hour, on a life-cycle basis, than the competing candidates for utility investment, taking into account any comparative advantages of scale, lead-time, and reductions in uncertainties about future demand;

(4) Design of incentive and regulatory mechanisms for acquiring all possible cost-effective conservation in advance of less attractive utility investments; and

(5) A program for ranking and acquiring the additional resources, if any, that may be needed to meet anticipated post-conservation energy needs.

It is during the last of these steps that long-range contracts for PURPA resources should come into play. That is, long-term commitments to buy independently-generated power should await a determination of how much the system is likely to need after it has exhausted less costly conservation. At the same time, of course, the system must position itself to acquire that conservation. If, in the process, it discovers that it does not presently need additional resources of any kind, then there is no policy or legal basis for offering long-term PURPA-related commitments (or for building new utility-sponsored power plants). If the system does have immediate acquisition needs, it should give independently-owned resources a chance to meet them under long-term avoided-cost contracts, while providing a means more rational than "first-come-first-served" for deciding whom to choose if long-term offers cumulatively exceed system needs.[26]

In any jurisdiction, regardless of its needs for new resources, PURPA will continue to create near-term opportunities for entrepreneurs who can produce power more cheaply than the utility's current stock of power plants. But long-term contracts based on the high cost of new plants should await a finding that in fact there will be new plants to displace after the system has exploited its cost-effective conservation options. A policy of at least comparable circumspection is appropriate for new utility-sponsored plants; such commitments are inappropriate until both conservation and PURPA options have been exploited.[27] Given the promise of these and other alternatives, we know of no

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[26] The most promising ranking system appears in Chapter 36 of the Maine Public Utilities Commission's Rules and Regulations ("Cogeneration and Small Power Production"); see note 18 above and sources therein cited.

[27] Indeed, conservation and PURPA options hardly exhaust the list of promising alternatives to utility-sponsored plants:

> Load management programs that shift consumption away from peak periods, without necessarily affecting total consumption, are an obvious example. Also worth investigating is the willingness of large industrial and commercial customers to sell interruption rights to the utility system, which would provide additional reserves in the event of unexpected shortfalls.
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> ...
>
> [In a related development], [t]he Pacific Northwest has pioneered ... dual-fuel industrial loads that can switch from electricity to gas (or, of course, vice versa) if system needs dictate.

Least-Cost Planning, note 1 above, at 324 & 341.

North American system that could prudently launch a utility-sponsored power plant at this time.

The four-state Pacific Northwest region provides a useful case study in least-cost planning. Idaho, Montana, Oregon and Washington collectively have deferred nearly all investment in new power plants, by setting low avoided-cost rates under PURPA and cancelling numerous utility-sponsored units. They reached this decision following a region-wide "least-cost plan" that identified the equivalent of at least 5150 average megawatts (45,000 GWh/yr) of conservation, available through efficiency standards and utility investment over twenty years, at an average cost of less than two cents per kilowatt-hour.[28] That resource was large enough to displace all new large-scale plants indefinitely. In evaluating and granting priority to its cost-effective conservation, the Northwest was acting consistently with PURPA. Where independently-owned generation costs more than conservation, PURPA's teaching is that the independent generators should be built only if they "avoid" comparably or more expensive power production, which the conservation cannot displace. This is an issue that every state can and should investigate for itself. Nevada and Michigan regulators have already joined the Northwest in such "least-cost" inquiries.[29]

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[28] See Northwest Power Planning Council, Northwest Electric Power and Conservation Plan, at 5-12 (1983). A revised version of the Plan was issued in 1986.

[29] See Wellinghoff & Mitchell, A Model for Statewide Integrated Resource Planning, Public Utilities Fortnightly, Aug. 8, 1985 (overview of least-cost planning in Nevada); Michigan

This testimony should not be construed as a call for blind deferral of PURPA resources and other generators; rather, it is a plea to let conservation compete fairly for ratepayer dollars. PURPA resources obviously belong in this competition; indeed, given their manifest advantages over conventional large-scale units, they may prove the only competitors who matter. It is not necessary to amend PURPA in order to minimize system costs; rather, states should apply its mandate in conjunction with least-cost planning techniques whose worth has already been demonstrated.

Department of Commerce, Michigan Electricity Options Study: Study Guide (January 1986) (describing Michigan's ongoing least-cost electricity options study).

TESTIMONY ON
PURPA IMPLEMENTATION BEFORE THE
U.S. SENATE ENERGY AND
NATURAL RESOURCES COMMITTEE

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Summary

The State of Ohio is one of the last states to implement PURPA, Section 210, and has yet to reap any benefits therefrom. The stated objectives behind the passage of PURPA (conservation of electric energy; efficient electric utility use of facilities and resources; equitable rates to utility customers; development of cogeneration and small power production) are benefits to be gained from proper implementation of PURPA. For Ohio, this could be the least-cost alternative to new power plant construction, as well as a better matching of marginal growth in electricity demand than large baseload generating units. This would result in deferring or cancelling the need for additional large and costly utility power plants.

To further implement PURPA, the following issues demand state and FERC regulatory attention:

Sanctity of Contracts - State utility commission approved contracts should not be subject to a review every 5 years, as is currently the case in Ohio.

Avoided Cost Rates for Cogeneration - Payment of a utility's full avoided cost should be made.

Levelized Payments to Cogenerators - The ratepayer is assured of cost effective development of cogeneration resources in the long-term if avoided cost payments for cogeneration capacity are made at a fixed level for the life of the long-term contract.

Reimbursement of Utility Payments to Cogenerators - Utilities should be assured that they will be reimbursed for payments to cogenerators made according to state utility commission approved contracts.

Back-Up Power - PURPA seeks to assure cogenerators the availability of: back-up power; supplementary power; maintenance power; and interruptible power.

Wheeling/Access to Transmission Systems - Cogenerators should have access to electric transmission systems so that the benefits of cogeneration for ratepayers can be maximized.

Utility Ownership - Public utility ownership of qualifying facilities to 50% should not be changed.

The Office of Consumers' Counsel offers the following recommendations regarding PURPA's implementation keeping in mind that the preponderance of problems is not a result of the statute itself, but the wide latitude taken by states in its implementation and FERC's lack of enforcement.

PURPA Should Not Be Changed - There has been no substantial evidence offered that demonstrates that PURPA is not effectively working or that further legislation is needed. For obvious reasons, criticism of PURPA has almost exclusively come from the electric utility industry. With the exception of the belief that PURPA is not being implemented fully or with sufficient rapidity, we have yet to hear serious complaints from ratepayers or consumer groups.

Implementation refinements at the state level with the assistance of FERC will be necessary to assure that ratepayers are well served by independent energy producers. Due to the great variance of state energy needs of the different states, states should continue to be free to solve their particular problems in the way they deem most efficient and economical.

Introduction

We are pleased to have this opportunity to address the implementation of PURPA on behalf of the residential utility consumers of Ohio, William A. Spratley Ohio Consumers Counsel, the Statutory representative of Ohio's residential utility consumers.

First, we would like to state the Office of Consumers' Counsel's position with respect to PURPA, Section 210, Cogeneration and Small Power Production, as advocated by our nine-member Governing Board.

The Office of Consumers' Counsel Governing Board supports, by resolution the development of cogeneration and small power production in Ohio and payment of rates to Qualifying Facilities (QFs) equal to the purchasing utility's full avoided costs (Bd. 84-4 Attached as Exhibit KMK-1). In addition, the resolution distinguishes between rates other than a utility's full avoided cost as a subsidization of QFs by other ratepayers or a disincentive for the development of QFs.

PURPA Benefits

In states where cogeneration is actively being implemented, the results envisioned by the sponsors of PURPA are being achieved through the use of market forces and competition rather than through monopoly of energy supply and regulation.

Some of the benefits envisioned include a better match of marginal growth in electricity demand than through use of large baseload generating units, thereby deferring or eliminate the need for additional large and costly utility power plants. The capital investments and operating costs, including any project cost overruns, become the financial risk of the cogenerator when a utility purchases cogenerated power and not the utility or its ratepayers. Ratepayers, therefore, do not pay for availability of power supplies not received or for overly expensive power. By virtue of the fact that the local utility buys power in small increments, the ratepayer pays nothing extra. Often, the utility is relieved of the financial burdens of building large, new units or firing old, inefficient and costly generating units. In turn, the utility's cost of capital is reduced.

Since full avoided cost is the cost incurred by the utility to generate or buy from another source, the ratepayer pays no more for electricity purchased by the utility from a cogenerator than for electricity produced by the utility itself. Because of this, cogeneration by industry can be encouraged to a maximum extent without increasing retail power rates. This is true, as well, for areas of the country where there is a surplus of electricity. The addition of cogenerated electricity to the utility system will not adversely affect ratepayers. The cogenerator will not receive an avoided capacity payment if the utility has excess capacity now and in the foreseeable future. In these instances, the avoided cost payment will be based solely on the utility's avoided energy cost which, primarily, is the cost of fuel the utility can avoid purchasing for its plants if it buys cogenerated electricity instead.

Through the use of cogeneration ratepayers will avoid the rate base effect of large, new, and expensive baseload capacity. In many cases, ratepayers will be paying for cogenerated electricity at a rate that is below the utility's avoided energy cost alone.

There are additional benefits of cogenerated power by industry in that:

- Greater use of renewable fuels such as biomass is encouraged by cogeneration/small power production.
- U.S. industry becomes more competitive due to cogeneration's reduction in production costs.
- Cogeneration lead times are one to three years vs. ten to fourteen years for large coal or nuclear facilities.
- Cogeneration has fewer emissions per kilowatt hour of electricity generated than in conventional utility generating facilities.

Background of PURPA Implementation in Ohio - It is necessary to state up front that justified problems/criticisms of PURPA implementation in Ohio are the result of the difficulty of implementing something totally new. The problems/criticisms discussed below can be resolved without altering the provisions of PURPA.

It was a full year after the Federal Energy Regulatory Commission (FERC) issued Order No. 69 (Feb. 19, 1980) and 18 C.F.R. §292.101-.602 (1980), that hearings were held by the Public Utilities Commission of Ohio (PUCO) pursuant to 18 C.F.R. §292.401 on March 16 and 17, 1981. The PUCO Opinion and Order implementing PURPA Section 210 in Ohio was issued on November 17, 1982. The Order stated that the record at that time was insufficient to fully develop the procedures for implementing Section 210 of PURPA. The Order went on to state that it was not possible to set out a step-by-step formula for determination of a utility's avoided capacity costs. Because of this uncertainty/reluctance on behalf of the Commission, an extended period for filing comments by the parties ensued. There have been no substantive revisions to the Opinion and Order since its initial issuance in November 1982, until the issuance on April 1, 1986 of the Opinion and Order in the ENCOA/Cincinnati Gas & Electric Company Case. In that case, approval was sought for a cost methodology in the determination of a cogeneration/small power production rate for a Qualifying Facility with a Capacity in Excess of 100 Kilowatts. April 1, 1986 and the Entry on Application for Rehearing in that case on May 28, 1986.

The Public Utilities Commission of Ohio has yet to establish a method for calculating avoided capacity costs, nor has it favored one method over another. The reluctance on behalf of the PUCO to implement PURPA Section 210 is most evident in its handling of the ENCOA/Cincinnati Gas & Electric Co. case mentioned above. In that case, the parties reached a stipulation based on three different methods of calculating avoided costs. The PUCO adopted the stipulation with critical modifications. Those modifications include a reopener every five years to determine avoided capacity costs to be paid to the cogenerator/small power producer within a range of 5¢/kwh to 12¢/kwh (rate for the first five years is set at 8.471¢/kwh with a .229¢ insurance provision). The range set by the PUCO has no formula to determine where in that range the avoided capacity cost should be set. The range was arbitrarily set, with the PUCO Chairman stating he hoped that within the next five years the staff of the Commission would be able to formulate an avoided capacity cost methodology. Part of the PUCO's insistence that a reopener be conducted every five years is that they were unable to secure any financial information from the small power producer (a 72 megawatt trash burning small power production facility). Three of the five PUCO Commissioners made statements that in the future they would insist that cogenerators/small power producers provide information on their financial situation before they would approve the contracts that came before them. This insistence that financial data be provided flies in the face of the PURPA statute, the FERC's rules, and FERC's interpretation of the statute, the rules, and the Conference Report. In the Conference Report the Legislature stated that . . .

> "It is not the intention of the Conferees that cogenerators and small power producers become subject...to the type of examination that is traditionally given to electric utility rate applications to determine what is the just and reasonable rate that they should receive for their electric power.[1]

The FERC's avoided cost rule, based on the statute and the legislative history was upheld on appeal to the United States Supreme Court in 1983. See, American Paper Inst. v. American Elec. Power, 76 L. Ed.2d 22 (1983). The U.S. Supreme Court held that "FERC did not act arbitrarily or capriciously in promulgating the full avoided cost rule." In addition, in its

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[1] Conference Report on H.R. 4018, Public Utilities Regulatory Policies Act of 1978, H. Rep. No. 1750, 97, 95th Cong. 2d. Sess. (1978).

Order 69, the Federal Energy Regulatory Commission (FERC) discussed the situation in which a qualifying facility and an electric utility have entered into an agreement and circumstances later change. As noted by FERC:

> §292.304(b)(5) and (d) Legally enforceable obligations.
>
> Paragraphs (b)(5) and (d) are intended to reconcile the requirement that the rates for purchases equal the utilities' avoided cost with the need for qualifying facilities to be able to enter into contractual commitments based, by necessity, on estimates of future avoided costs. Some of the comments received regarding this section stated that, if the avoided cost of energy at the time it is supplied is less than the price provided in the contract or obligation, the purchasing utility would be required to pay a rate for purchases that would subsidize the qualifying facility at the expense of the utility's other ratepayers. The Commission recognizes this possibility, but is cognizant that in other cases, the required rate will turn out to be lower than the avoided cost at the time of purchase. The Commission does not believe that the reference in the statute to the incremental cost of alternative energy was intended to require a minute-by-minute evaluation of costs which would be checked against rates established in long-term contracts between qualifying facilities and electric utilities.
>
> Many commenters have stressed the need for certainty with regard to return on investment in new technologies. The Commission agrees with these latter arguments, and believes that, in the long run, "overestimations" and "underestimations" of avoided costs will balance out.
>
> Paragraph (b)(5) addresses the situation in which a qualifying facility has entered into a contract with an electric utility, or where the qualifying

> facility has agreed to obligate itself to deliver at a future date energy and capacity to the electric utility. The import of this section is to ensure that a qualifying facility which has obtained the certainty of an arrangement is not deprived of the benefits of its commitment as a result of changed circumstances. This provision can also work to preserve the bargain entered into by the electric utility; should the actual avoided cost be higher than those contracted for, the electric utility is nevertheless entitled to retain the benefit of its contracted for, or otherwise legally enforceable, lower price for purchases from the qualifying facility. This subparagraph will thus ensure the certainty of rates for purchases from a qualifying facility which enters into a commitment to deliver energy or capacity to a utility.
>
> (Emphasis added).

The import of this discussion is clear: FERC recognized that circumstances change over time and that the obligations of the parties as expressed in their freely-negotiated agreement should be recognized, understood, and adopted by state regulators.

The rule and the FERC's interpretation thereof make it clear that, once the parties to such an agreement have entered into the contract in good faith, that it should thereafter be honored by state regulatory agencies. A cogenerator needs a long-term contract for the sale of electricity to a utility in order to secure financing for the facility. The economic analysis justifying the worthiness of a cogeneration project mandates the assurance that the contract entered into with a utility for sale of cogenerated power will not be subject to revision at a future date. Projections by a utility of its avoided costs have at least as good a chance of being too low as too high, and therefore, should not be subject to 20-20 hindsight if conditions change years later.

Unfortunately, through its Order in the ENCOA case, the PUCO has allowed a reopener at a later date of a contract entered into voluntarily by a small power producer, utility, and other parties. This procedure threatens the sanctity of contracts making financing of this as well as other cogeneration projects virtually impossible.

Important Issues in Implementation of PURPA

As is apparent from the above discussion of the ENCOA/ Cincinnati Gas & Electric case there are many questions that are as yet unanswered or addressed by the PUCO before implementation of PURPA can become a reality in the State of Ohio. Some of these questions include:

1. When cogeneration occurs, is it in the public interest to have such facilities built only to meet the cogenerator's own needs (displacement of power) or should such facilities be sized to be economic net sellers of electricity or steam? Since cogeneration is an economic proposition, projects will be developed measuring cost savings relative to existing and forecasted retail rates and not theoretical avoided cost. This is evident in the Cincinnati Gas & Electric service territory where the major industrial and commercial customers have already determined the rate at which cogeneration becomes an alternative to the rates they would pay due to the conversion of the Zimmer Nuclear Power Plant to a Coal Fired Power Plant with a cost of $3.6 billion as the ceiling for recovering from ratepayers.
2. How do we reconcile the existence of utilities with substantial surplus capacity with those utilities without excess capacity and the opportunity for developing cogeneration capacity throughout the State irrespective of service territory?

3. Does ratepayer risk increase with cogeneration and small power production vs. ratepayer risk from utility constructed units.

4. Should a standard avoided cost methodology be adopted?

5. Should interconnect standards or changes be monitored by regulators?

6. Should the PUCO set stand-by rates and other auxiliary service rates for QFs? (There are QFs in the State currently operating without auxiliary service rates.)

7. What is the role of cogeneration in load forecast cases?

8. How should regulators approach wheeling and power pooling?

9. Can new coal technologies like the fluidized bed become part of cogeneration development?

10. Is the PUCO's insistence of obtaining cogenerators' financial information lawful?

All of the questions listed above will be the topic of discussion in an upcoming meeting of cogenerator/small power production supporters within the State of Ohio, to be held in the near future. A plan of action will be developed to encourage the PUCO to address the implementation of PURPA within the State of Ohio. A report will be submitted to the PUCO based on this plan of action, with the hope that some action will be taken by the Commission to address the problems outlined above.

Though several studies have estimated strong potential, there is relatively little cogeneration/small power production in Ohio. For example, a 1983 U.S. Department of Energy report estimated that Ohio's private enterprise could produce 1,500 megawatts of electricity mostly from waste heat and manufacturing by-products.[2] Consolidated Natural Gas has pointed out from their review of the U.S. Department of Energy study that 5,503 megawatts or about 13% of the Nation's cogeneration potential of 42,824 megawatts exist in Ohio, Kentucky, Pennsylvania and West Virginia.[3] Consolidated clearly links job-creation and job-retention in the Ohio Valley to developing this virtually untapped cogeneration potential.[4] To date, the electric utilities of Ohio have been very successful in their opposition to cogeneration.

Encompased in the questions listed earlier are specific issues on the implementation of PURPA. Below is a discussion of these specific issues that have been misunderstood/improperly addressed by the PUCO as well as by other state utility commissions. These are areas in which FERC in most cases, could provide regulatory guidance so that PURPA can work efficiently.

Sanctity of Contracts - This issue was discussed in detail in an earlier section. Briefly we reiterate that state utility commission approved contracts should not be subject to a review/change at a later date.

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[2] Industrial Cogeneration Potential (1980-2000) Targeting of Opportunities at the Plant Site (TOPS). Final Report by General Energy Associates, Philadelphia, PA; for the U.S. Department of Energy, (May 1983)

[3] Summary of "Cogeneration: A Congressionally - Inspired Success Story Heard Everywhere But in the Ohio Valley", Consolidated Natural Gas Company, October 10, 1983; p. 2. See also Cogeneration: A Congressionally-Inspired Success Story Heard Everywhere But in the Ohio Valley, October 17, 1983.

[4] Ibid.

Avoided Cost Rates for Cogeneration - FERC rules should not be modified to encourage states to develop innovative pricing approaches that pay less than full avoided costs, as has been suggested by the electric utility industry. As was discussed in the section on the benefits of PURPA, payment of full avoided costs encourages cogeneration and does not result in increasing retail power rates. Since this criticism of FERC's rule has been explored at length, we will not be exhaustive in our comments.

Levelized Payments to Cogenerators - Levelized payments are at a fixed level for the life of a long-term contract. State commissions are permitted, but not required, to direct utilities to enter into levelized payment arrangements for purchasing cogenerated electricity.

Cogenerators frequently need levelized payments to enable them to pay off their financing for the capital expenditures of the facility in the early years. This is achieved by selecting a level at or below the utility's avoided cost for the life of the contract. This can result in a somewhat higher than expected avoided cost in the early years and a somewhat lower than expected avoided cost during the later years, hence a balancing affect. Routinely, cogenerators accept payments that are below avoided cost for the term of the agreement in exchange for levelized payments. Since levelized payments for avoided capacity are timed to coincide with the date the utility would otherwise have needed power, "front-end" loading is avoided, producing payments that are lower than the avoided capacity costs of the utility.

Reimbursement of Utility Payments to Cogenerators - Ratepayers should reimburse the utility for the cost of power when a utility purchases power at avoided cost under PURPA since it is acting in a prudent manner. Since the state commission has the authority to review contracts between utilities and cogenerators to make sure that they are consistent with avoided cost principles, the commission must be required to allow the utility to recoup the payment made under the approved contracts. By applying federal law, state commissions make cogeneration purchases prudent.

Back-Up Power - FERC should not allow the way a cogeneration project is financed to become a barrier to proper implementation of PURPA, which is currently the case with the August 1985 ruling in the Alcon Pharmaceutical case. According to this decision, third-party financed and owned cogeneration can be denied standby and back-up power by the local utility if the user of the cogenerated steam and electricity is a separate entity. This creates a barrier to proper implementation of PURPA, especially given that PURPA clearly sought to assure cogenerators back-up power. No industrial cogeneration can exist without back-up power when a cogeneration facility is temporarily shut down for maintenance and repairs.

Wheeling/Access to Transmission Systems - Allowing cogenerators access to electricity transmission systems would encourage greater development of energy efficient cogeneration and the use of renewable resources to generate electricity, contributing to lower energy costs. Qualifying facilities have no other market, unless a local utility agrees to delivery the power to others through use of its transmission system. This leaves QFs with a single market for their product, the local utility.

Utility Ownership - Competition in the utility field while simultaneously promoting fuel efficient and renewable resource facilities will be destroyed if public utility ownership of QFs is changed from the current 50% level. Diversifying the sources of utility generation was one of the reasons behind congressional limitation on utility ownership. Congress felt it was time to encourage new entrants into a marketplace that would be free of the regulatory restraints and guarantees to which utilities were subject.

Cogeneration negotiations with utilities could be stalled and utilities would be encouraged to engage in even more delays if the utility has unlimited ownership in the facilities. Changes in utility ownership levels would encourage utilities to shift productive assets into, or to acquire qualifying assets in, unregulated divisions or subsidiaries that would be operated for the benefit of stockholders, rather than to produce balanced benefits to ratepayers and stockholders.

Recommendations

The Office of Consumers' Counsel recommends that PURPA not be changed. The preponderance of problems with PURPA to date, are not a result of the statute itself. Rather, the problems are a result of the wide latitude taken by states in their implementation of PURPA. This problem is magnified by FERC's lack of enforcement of the rules it promulgated.

To this point in time, there has been no substantial evidence offered to demonstrate that PURPA is not effectively working or that further legislation is needed.

When the criticism of PURPA is reviewed, almost exclusively, the criticisms come from the electric utility industry, for obvious reasons. With the exception of the feelings that PURPA is not being implemented fully or with sufficient rapidity, there is yet to be brought forward serious complaints from ratepayers or consumer groups.

In conclusion, implementation refinements at the state level with the assistance of FERC, will be necessary to assure that ratepayers are well served by independent energy producers. Due to the great variance of individual state energy needs, states should continue to be free to solve their particular problems in the way they deem most efficient and economical.

STATEMENT OF PACIFIC GAS AND ELECTRIC COMPANY
BEFORE THE
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

JUNE 3, 1986

Pacific Gas and Electric Company (PGandE) appreciates this opportunity to describe to the Senate Energy Committee its experience under Sections 201 and 210 of Title II of the Public Utility Regulatory Policies Act (PURPA), to identify policy issues that have emerged as a result of that experience, and to suggest means of resolving those issues consistent with the intended objectives of the legislation.

PGandE is incorporated under the laws of the State of California and is a regulated public utility under the California Public Utilities Code. PGandE distributes gas and electricity throughout northern and central California, and is the largest combined gas and electricity utility in the United States. Its service area includes a population of approximately 10.2 million people.

I. Executive Summary.

The magnitude of cogeneration and small power production in California stimulated by the Public Utility Regulatory Policies Act is unprecedented. No other state has experienced such an overwhelming response of "qualifying facilities" (QFs). For PGandE, whose system demand is about 16-17,000 MW, over 8,000 MWs of QF power now is under contract. Statewide, the three major regulated utilities have contracted for over 16,000 MWs of QF power. A total of 3,095 MW of QF power is already in operation out of a total generating capacity of 41,077 MW, or seven and one-half percent. Without question, the response to enactment of PURPA has exceeded all expectations; unfortunately, the combined capacity of QF projects proposed in California also has exceeded forecasted needs.

The electric consumer was the intended beneficiary of PURPA. Though the statute was designed to stimulate the development of new decentralized, non-utility power sources, Congress insisted in Section 210 that the price paid for QF power must "be just and reasonable to the electric consumers of the electric utility and in the public interest." Congress also required that the Title II program provide "increased conservation . . . increased efficiency . . . and equitable retail rates for electric consumers." (Sec. 2 Findings.) Utilities were required to purchase QF power, but at no higher than the "incremental cost to the electric utility of alternative electric energy" (Sec. 210(b)), which was defined as the cost to such utility of the electric energy which, but for the purchase from the QF, the utility "would generate or purchase from another source." (Sec. 210(b), emphasis added.)

However, as implemented by the Federal Energy Regulatory Commission (FERC) and the California Public Utilities Commission (CPUC), the statute has induced development of Qualifying Facility (QF) power production at the expense of PURPA's consumer protection goals. In California, electric consumers are paying, and for the foreseeable future will pay, substantially higher electric rates, and will have less assurance of service reliability, as a direct result of the overstimulation of the QF industry. Specifically, the implementation of PURPA in California has given rise to the following problems:

o Payments in Excess of Avoided Cost for Power that is Not Needed. For PGandE's customers, overpayments for energy alone -- excluding capacity payments -- have risen from $17.9 million in 1983 to $45.3 million in 1985, for a three-year total of a startling $102 million. This is just a result of forecast error in system efficiencies resulting from regulatory orders. An additional overpayment because of the use of artificially high gas prices has produced an additional energy overpayment of $159 million over the same three-year period. The escalation in overpayments will be even more dramatic in the next few years as QF projects come on-line under the CPUC's authorized Interim Standard Offer No. 4 -- a contract with fixed energy prices dramatically higher than anticipated avoided costs. In addition, PGandE estimates that by 1990 it may be required to purchase 4,500 to 5,000 MW of unneeded capacity from QFs.

Many factors contribute to this problem: 1) forecasts used as the basis for prices and the lack of an adjustment mechanism if actual conditions diverge from projections; 2) paying for capacity in advance of need; and 3) failure to reflect cheaper sources of power adequately in the calculation of avoided costs.

o Integration of QF Power into the Utility System. For PGandE to meet its statutory obligation to serve, it must have adequate control over generation sources to vary electrical output to match its customers' needs. In California, QF contracts have mandatory take and limited curtailment which result in uneconomic dispatch. Such contracts do not provide the assurance that QFs will deliver power when power is needed, or refrain from delivering it when it is not. Moreover, QFs are not dedicated by statute and regulation to provide service to customers, as utilities are. Thus, as unregulated QFs become an increasing percentage of PGandE's overall generation resources, a significant risk arises that PGandE will be unable to meet customer service needs.

o Eligibility for PURPA Status. Minimal FERC efficiency standards for cogeneration projects have promoted development of inefficient "PURPA machines" that do not achieve PURPA's goal of conservation. Although one of the statute's goals was to reduce dependency on oil and gas for electric generation, FERC and CPUC rules on cogeneration fuel efficiency have failed to achieve that end. In California, energy from oil- or gas-fired cogeneration can displace non-oil or gas energy from utility resources, including coal, geothermal and even hydro. In addition, in large gas- or oil-fired cogeneration projects in California, production of electricity can greatly exceed that needed for the thermal output. Such token cogenerators are really unregulated, small electric power companies who, unlike regulated utilities, are guaranteed a market for their product at subsidized prices, and who have no obligation to serve or even to integrate their generation with the utility's operation.

o Consistency Between PURPA and Pro-competition Energy Policy. As this Committee is aware, national energy policy, current conditions of supply and demand for energy, and current competitive pressures to which utilities such as PGandE must respond are very different than when PURPA was passed. The administration's National Energy Plan (NEP IV) places much more reliance on achieving security of supply and economic efficiency through competition and market-based policies. Current supply/demand conditions also reduce the urgency of or economic premium on developing non-utility, decentralized sources of generation.

Finally and perhaps most important, utilities such as PGandE are increasingly "market driven." Utilities face pressure from retail and wholesale customers who wish to go "off-system" to obtain better rates by developing their own generation or buying it from other utilities, from federal and state regulators to accommodate such customers to become non-core (e.g., FERC's Order 436, Docket No. RM85-1), and competitive pressure to engage in increased coordination transactions (surplus power purchases or sales) with other utilities to keep rates low and avoid construction of new capacity. There is also a large segment of the industry, primarily the federally-owned and municipally-owned utilities, whose participation in competitive wholesale and retail markets is subsidized by special tax benefits, access to low cost power, etc.

PGandE cannot retain existing customers or compete for new customers in this emerging market if it is literally "forced" to purchase more power than it needs, at higher than market prices, or to use its valuable transmission lines to carry uneconomic QF power at the expense of cheaper energy from another source. In short, Title II of PURPA, as implemented by the FERC and the states, has erected significant barriers to utility participation in competitive bulk power and retail markets.

The problems with PURPA stem less from the legislation itself than from FERC's implementing regulations and their interpretation in California. Absent revisions in these FERC regulations and more stringent FERC guidelines to the states, electric customers face a future of uncertain service reliability and unnecessary rate increases. And electric utilities will be at a competitive disadvantage in an increasingly competitive electric power market.

To narrow the gap between PURPA's promise to electric consumers and its fulfillment, and to ensure consistency with present energy policy, PGandE recommends the following revisions to the FERC rules and state guidelines:

- Utilities Should Not be Mandated to Pay Full Avoided Costs. FERC rules should be modified to require states to develop pricing approaches that will both stimulate QF development and achieve maximum rate benefits for electric consumers. Thus, ratepayers should, at worst, be indifferent between power supplied by the utility and power purchased from the QF. At best, ratepayers should share in the economic benefits of QF power which can be provided at less than the utility's avoided cost.

- Capacity Payments Should be Restricted. FERC rules should be amended to direct state regulators to allow capacity payments for QFs only for those years in which a deferrable or avoidable utility resource can be specifically identified in a near-term resource plan.

o Stricter Operational Requirements Should be Mandatory. FERC rules should be modified to assure that QFs will -- through negotiated contracts with the utility -- provide needed performance characteristics to achieve system efficiency and reliability.

o Stricter Efficiency Standards Should be Required. FERC rules governing efficiency should be tightened to withhold QF status from unregulated "PURPA machines" that are designed primarily as unregulated electric power plants and which do not achieve actual efficiency improvements over central station generation.

A first step in implementing these recommendations is for this Committee to request the FERC to expeditiously undertake and complete an investigation and modification of its PURPA regulations. The investigation should focus on those regulations (federal and implementing state regulations) that should be modified to correct the problems described above of overpayment, excessive purchase, non-integration and inefficiency. The final step would be a FERC notice of proposed rulemaking of new FERC regulations and guidelines to states. If the FERC fails to complete such investigation and initiate a rulemaking in six months, Congress should enact legislative amendments to PURPA that direct FERC and the states to implement the recommendations set forth in this statement.

II. PGandE's Implementation of Title II of PURPA.

A. PGandE has been committed to achieving the conservation and alternative energy goals of PURPA.

When it was enacted in 1978, the stated intent of PURPA was to a) conserve electric energy, b) optimize the efficient use of facilities and resources by electric utilities, and c) provide equitable rates for electric consumers. To help achieve these objectives, Congress believed that federal law should stimulate development of certain types of alternative power supplies. Title II of the statute was intended to reduce perceived institutional barriers to development of such non-utility, decentralized power production in a manner that would provide economic and operational benefits to the electric consumer.

In 1981, PGandE formally adopted as a corporate goal a commitment to encourage maximum use of cost effective conservation, cogeneration and small power production from renewable resources. PGandE estimates that its conservation program will allow the Company to avoid significant investments for new capacity. Indeed, PGandE's expenditure of $135 million for conservation programs in 1984 produced energy savings of 2,754,800 barrels of oil in that year.

PGandE has also given cogeneration and small power production a high priority for development in its corporate mission. A substantial amount of Qualifying Facility production has been developed to date in PGandE's service area. Since 1980, PGandE has signed contracts for over 8,410 MW of QF capacity. As of March 31, 1986, PGandE has approximately 1,400 MW of QF capacity in operation from 95 cogeneration and 257 small power projects. By 1990, PGandE anticipates that approximately 3,000 MW of cogeneration and 2,000 MW of small power production will be in operation in its service area. Thus, while in 1985 QF production accounted for over seven percent of PGandE's total generation, by 1990 it will account for approximately 20 percent. (See Exhibits 1 and 2)

In addition, PGandE has also built several renewable power production facilities (without all the subsidies and guarantees provided by PURPA): the Solano wind turbine in Solano County, the Gerber compressor station project, using waste heat that was formerly vented and lost; and a photo voltaic generation facility at PGandE's Department of Engineering Research in San Ramon.

B. QF development in PGandE's service area now jeopardizes economic and efficient service to electric consumers.

While the development of alternative energy from non-utility sources has proceeded rapidly in California, the manner in which PURPA has been implemented by the FERC and by California has been at the expense of and detrimental to achievement of the consumer objectives of PURPA -- equitable rates, conservation, and efficiency. In California, electric consumers already are paying substantially higher electric rates, and unless changes are made, the problem will only get worse in the future. As shown in

Exhibit 3, energy payments to QFs over the last few years have exceeded PGandE's actual avoided cost. For example, in 1985, PGandE's customers paid $45.3 million more for energy than if PGandE had generated or purchased such power from non-QF sources. By 1990, the potential overpayment for both capacity and energy could reach almost $1.5 billion. (See Exhibit 4)

In addition, it is not clear that energy resources have been conserved: most of the energy delivered to PGandE's system has come from oil- and gas-fired cogeneration, not renewable biomass, wind power, or solar energy.

Finally, the pricing mechanisms and purchase requirements under the FERC and California regulations implementing PURPA have caused a major misallocation of economic resources. As described in more detail below, much more QF capacity has been developed in California than is needed. QF development has borne little relationship to utility resource plans. Under existing regulations, California utilities have no contractual ability to integrate and coordinate the operation of QF facilities with their primary electrical systems in order to efficiently meet electric load. In short, QF generation is not helping to meet consumer demand for efficient, reasonably priced electric energy.

1. The results of QF development in PGandE's service area.

As shown in Exhibit 1, most of the projects currently operational in PGandE's system are cogeneration. The majority of these projects sell power to PGandE under Standard Offer No. 2 with levelized firm capacity payments. By 1990, it is expected that an overwhelming percentage of QF facilities operating in PGandE's territory will be cogeneration. (See Exhibit 2)

Exhibits 7, 8 and 9 compare signed contracts by technology and contract type. It should be noted that over 64 percent of the signed QF contracts are under Interim Standard Offer No. 4, a contract with energy and capacity prices that are expected to be dramatically higher than actual avoided cost.

Cogeneration not only is expected to constitute the greater percentage of QFs in operation by 1990, but it is also expected to provide substantially more energy deliveries than any other technology. As Exhibit 10 shows, for the year 1985 cogeneration energy deliveries far exceeded those of any other technology. This trend will continue. As Exhibit 11 shows, it is anticipated that by 1990 the ever-increasing level of energy deliveries from QFs will reach approximately 25 billion kilowatt hours -- the majority of which will be provided by gas- and oil-fired cogeneration projects.

The rapid development of QF projects is a direct result of the availability of very favorable standard offer contracts in California. In particular, the development in 1983 of the CPUC's Interim Standard Offer No. 4 (SO #4), a long-term fixed energy and capacity price contract, was a boon to the QF industry. Unfortunately for electric customers, unlimited availability of the contract coupled with high energy and capacity prices will result in significant overpayments for QF power. Indeed, QF production will constitute approximately 20 percent of PGandE's generation by 1990 and 60 percent of its production expense. (See Exhibit 6) This will have major operational and economic impacts, as described below.

The CPUC, finally recognizing this adverse ratepayer impact, suspended the offer in July of 1985. However, by that time PGandE had been compelled to enter into over 5,000 MW of SO #4 contracts. In March of this year, the CPUC also suspended Standard Offer No. 2, a contract with fixed capacity payments and variable energy payments, again because of the potential of ratepayer overpayments for capacity. Unfortunately, the CPUC expects to reinstate Standard Offer No. 2 later this year. In the meantime, Standard Offers Nos. 1 and 3 (for 100 KW and less), with variable prices and no operational requirements, remain available.

2. The amount of QF power for which PGandE has been contractually obligated to purchase greatly exceeds its near-term needs and displaces existing resources.

a. Open-ended purchase obligation.

Mandatory purchases from QFs jeopardize PGandE's ability to maintain a proper balance of sources of generation to assure reliability, security of supply and stability of price. FERC and CPUC regulations have required PGandE to purchase power it does not need now or in the near term. (See Exhibit 12) Purchase requirements should be, but are not, matched to resource needs identified in PGandE's future resource plan. The result is a significant misallocation of economic resources (both investment dollars and customer rates) towards unneeded QF development. In addition, investment in future QF innovation and development is inhibited because existing QF projects saturate foreseeable needs.

b. Economic and operational impacts.

The lack of utility operational control over QF power deliveries can lead to uneconomic operation of the utility system. On a daily basis, QF power deliveries, which do not adjust to load, can displace other, more economical sources of power such as hydro or economy energy purchases. A comparison of average QF prices versus PGandE's average cost of power from the Northwest shows how significantly the ratepayer can be put at an economic disadvantage. While QF average prices per kilowatt hour range from approximately $.04 to as much as $.074, the daily average cost per kilowatt hour of Northwest power ranges from $.016 to $.026.

Not only does the lack of operational control lead to diseconomies in dispatching the system, the cycling of utility plants in order to accommodate deliveries of QF power can cause wear and tear over and above that which would normally be experienced. The result is higher maintenance and possibly retrofitting costs of existing thermal plants in order to achieve the necessary cycling capability.

c. Recommended policy.

The open-ended obligation created by Section 292.303 of the FERC regulations must be revised to require purchases of QF capacity and energy only to the extent that deferrable or avoidable utility capacity and energy can be specifically identified for the near term.

While the FERC regulations do not require utilities to pay for capacity they do not need, it does require utilities to purchase energy even when it means displacing the utility's own resources or other sources of cheaper purchased power. The FERC regulations indicate several factors that can be taken into account in determining the price to be paid for such energy. However, the regulations do not adequately address the problem of displacement of cheaper sources of energy.

The CPUC requires PGandE to pay for capacity even in the absence of a deferrable or avoidable utility resource. Payments in such circumstances are based on a "shortage value" concept, i.e., the value of increased system reliability created by energy deliveries. In a situation where there is little or no utility control over the pattern of generation, as under current CPUC orders, shortage value payments are required for "as-delivered" capacity. QFs' selling power under as-delivered contracts have no obligation to provide the energy at any given time. Without operational requirements, the price signal is the only incentive for the QFs to deliver this as-delivered capacity at a time when it would arguably have some value to the utility's customers. However, it is interesting to note that the majority of QFs who deliver power on an as-available basis cannot alter their pattern of generation in response to any price signals. In this category would be wind and run-of-the-river hydro, where the availability of the resource dictates the generation pattern. For them, price signals are irrelevant.

There should be no requirement to purchase capacity and/or energy where reserve margins already are adequate. The need for capacity and energy should be determined on a near-term planning basis in order to allow development of new technologies and to adjust to predictable fluctuations in supply and demand for energy and capacity.

3. The price for QF capacity and energy in California has not been set at PGandE's true avoided cost, nor does it result in equitable benefits to ratepayers, as required under PURPA.

a. Legacy of QF subsidization.

Overly generous and rigid capacity and energy prices have been set in California by the CPUC. Capacity prices were based on forecasts that overstated the value to system reliability of additional energy availability and utility costs of installing generation, and did not adjust to changes in the cost of capacity once QF development began to accelerate. Energy prices also were set much higher than the actual marginal costs incurred, and failed to adjust to lower prices as additional increments of energy were added to the system by QFs. The requirement to base prices to QFs on forecasts of calculated "avoided cost" led inevitably to contentious debates on computer modeling assumptions and a heavy reliance on forecasts that were, as a result, consistently too high. The reliance on these forecasts led to fixed prices to QFs in excess of PGandE's actual avoided costs.

Sufficient QF production to meet resource needs could have been obtained at a much lower price than avoided cost. The result has been a long-term legacy of QF prices above those that would be set by an unregulated free market. Such subsidization contributes to higher rates to all customers, encourages more and more large customers of PGandE to bypass the electric system, and overstimulates QF production without regard to demand for such production.

The source of the problem is primarily FERC's regulation (18 CFR Sec. 292.304(b)(2)) which sets the price for QF power at the maximum rate allowable or full avoided cost, in order to encourage QF development. The CPUC, through its Decision No. 82-01-103, has fully implemented the FERC regulation and has not provided for lower prices even if they would elicit sufficient QF development.

b. Economic and operational impacts.

As Exhibits 4 and 5 show, by 1990 potential overpayments to QFs under Standard Offer No. 2 and Interim Standard Offer No. 4 could be staggering. While this is an illustration of the overpayments if all currently executed contracts go forward, one can easily see that the magnitude of the problem even under lesser levels of development is significant. The specter of ratepayers paying $1.3 billion more than necessary for QF power under current contracts should be sufficient impetus to re-examine the "full avoided cost" standard. Note also that because QF payments are such a large component of PGandE's electric costs, overpriced QF power will raise electric rates substantially. (See Exhibit 6) Future contracts should attempt to secure for the ratepayers some economic benefit from the QF program.

c. Recommended policy.

At a mimimum, ratepayers should be indifferent between power supplied by the utility and power purchased from the QF. In addition, to the extent that sufficient power can be provided by QFs at less than avoided cost, ratepayers should share in such economic benefits. Indeed, QF power must be priced at levels lower than the resources avoided to be an economic power source. One means of maximizing benefits to ratepayers consistent with encouraging development of QF generation is specifically to encourage a bidding system among QFs and to price QF energy on a real-time basis.

In a bidding process, PGandE's objective would be to develop a procedure in which QFs offering the most benefits to PGandE's ratepayers would sign the final SO #4 contract in an orderly and businesslike manner. In a current proceeding before the CPUC, PGandE proposed a procedure similar to the one currently being used by Central Maine Power. Under this method, once the avoided cost for a block of power is established, the utility sends Requests for Proposals (RFP) to known potential small power producers which might sell to the utility. These RFPs state that sales offers must be at or below the established long-term avoided cost, and that offers will additionally be judged on other criteria, such as price, level of ratepayer risk, etc.

Furthermore, reliance on forecasts which are never perfectly accurate should be reduced by urging states to implement real-time pricing programs. Real-time pricing (RTP) is the practice of continuously updating prices to reflect changes in the marginal cost of generating and delivering electricity. The term "real-time" implies that prices reflect costs as they occur, as opposed to historical or long-term projected costs. At the outset, it should be noted that RTP and the current QF pricing program are identical in concept -- both pay prices based on PGandE's marginal cost. The only fundamental difference is that RTP is based on recorded marginal costs that reflect actual system conditions instead of relying on forecasted marginal costs that reflect assumptions about those conditions. With RTP, payments to QFs will reflect actual load, actual power transactions, and actual generating resources operating and available to PGandE.

These recommendations could be adopted by a relatively straightforward modification in FERC's avoided cost regulation. The modification would require states to adopt an avoided cost methodology that mandates maximization of rate benefits to the utility's customers consistent with development of QF facilities. Full avoided cost would be set as a ceiling, and various methodologies that maximized such shared savings would be sanctioned.

4. Standardized contracts jeopardize operating reliability and control.

a. Erosion of reliability.

PURPA was not intended to displace the primary coordination and integration functions of a utility's electrical system. QF resources were intended to be integrated smoothly and efficiently into the utility's operations. Nor did PURPA intend to erode the operational responsibilities of a utility entrusted with an obligation to serve under state law.

In California, however, utilities must offer standard contracts that do not allow for project-specific negotiations. The standardized provisions do not provide control over dispatch to meet load, curtailment, minimum capacity and energy availability in the event of emergency, etc. Without operational controls over a rapidly increasing QF share of total generation, and with no control over the technological mix of QF power, PGandE and its customers incur greater costs.

Although Sec. 292.304(d)(2) of the FERC regulations contemplated that purchases of QF power could be made pursuant to a legally enforceable obligation, i.e., a contract, they do not require the use of "standard offer" contracts. In California, however, not only have standard offer contracts been adopted, but the CPUC also foreclosed utilities from actively initiating negotiated agreements. Indeed, the role of the California utility is restricted to merely responding to QF proposals for nonstandard contracts.

As a result of the CPUC implementation of the FERC regulations, utilities are essentially precluded from procuring economic or operational benefits for their ratepayers. The traditional give and take of contract negotiations, where each party can tailor an agreement to meet its needs, has been replaced with standard offers.

b. Economic and operational impacts.

QFs' lack of dispatchability or curtailment can have a significant detrimental impact on the ratepayers. Without dispatchability, the utilities cannot use QF power to follow load. Without the ability to curtail QFs during minimum load situations, utilities must back off their own generation. This lack of operational flexibility has not only an economic but also an operational impact. Reactive power requirements and other technical electrical operation needs can require a utility to operate certain plants on its system. These plants cannot be displaced by QF power and keep the utility system stable. Faced with excess energy during minimum load situations, the utilities must make difficult choices about dispatching the system in order to maintain stability. In some cases, this will require an uneconomic dispatch of the utility system in order to accommodate uncontrollable QF power deliveries to maintain system integrity. PGandE must also provide additional reserves to back up potentially unreliable QF capacity. (QFs, after all, have no regulated obligation to serve.) Thus while PGandE may be able to defer construction of its own power plants, it is also less secure in meeting its service obligation to consumers.

c. Recommended policy.

Standard Offers with contractually established, minimal performance requirements, and without a mechanism to address changing economic and system conditions, unfairly lock utility customers into an eement which today and in future years can become a burden. The changing operational needs of the utility, and the interest of electric customers in least cost service have been ignored in order to create a nurturing environment for QF development. While such an approach may have been justified when the QF program was in its infancy, it is no longer warranted. FERC regulations should require that QF contracts be negotiated individually to enable utilities to control dispatch of QF power to meet system load, curtailment, etc.

If standard offers are to be continued, the FERC regulations should be modified to specifically require both minimum operating controls and continuing jurisdiction of the regulatory agencies over the contract to assure that changes in conditions can be reflected in the prices or operating terms under which power is purchased. QFs which seek greater contract certainty can enter into nonstandard contract negotiations where both the needs of the QF and the reliability goals of the utility and its customers can be considered. Such operating controls, whether through regulations or individualized contracts, are especially necessary where QF capacity has become a significant proportion of total area generating capacity.

5. FERC-promulgated efficiency standards for cogenerators have encouraged creation of unregulated "token" QFs that generate electricity with little improvement in efficiency or conservation.

a. Unregulated PURPA machines.

Because of the FERC's present rules, numerous "token" cogenerators have qualified for QF status under PURPA. Typically, these cogenerators have inefficiently high electrical production for the amount of process steam they supply. These entities' primary purpose seems to be the generation of electricity at unregulated prices without any obligation to serve. Because of the large amount of such QF cogeneration in California, this poses a significant risk that electric consumers will not be served reliably.

The source of the problem is the FERC rules contained in Title 18, Part 242, Sections 292.205(a) and (b), which establish the standards which cogeneration projects must meet to qualify for PURPA benefits.

These efficiency standards risk increasing, not decreasing, the use of fossil fuels. For example, if a gas-fired facility installs a cogeneration project simply to meet its thermal needs, then the objective of decreasing fossil fuel use through increased efficiency is achieved. However, when the rules permit a cogeneration facility to be oversized to generate electricity, its gas use is likely to be greater. The extra electrical generation from the QF qualifies for avoided cost treatment, yet the regulated utility may have been able to produce the same power more cheaply and reliably. Under these circumstances, the goals of PURPA have been compromised.

Indeed, one may ask what PURPA-intended benefits the ratepayer has received from such token cogenerators. QF power is more expensive, less dispatchable and reliable, and scarce energy resources have not been conserved.

b. Economic and operational impacts.

As Exhibits 13 and 14 show, the payments by PGandE for power delivered for 1985 were made primarily to large industrial cogenerators. Although precise information is not available with regard to the thermal efficiency of these major cogenerators, PGandE has observed that such cogeneration facilities typically are sized in a manner that optimizes electrical revenue, and can only conclude that such factors went into the design of the facilities listed.

Aside from the issue of sizing of such facilities, there is no necessity for standard offer contracts to promote the sale of power from large industrial concerns. Large businesses such as those listed in Exhibits 13 and 14 are capable and competent to negotiate on an equal footing with the utility. Instead, again PGandE has been denied the ability to negotiate contracts with these concerns in a manner which would obtain operational flexibility and economic benefits for its ratepayers.

c. Recommended policy.

PGandE urges stricter efficiency standards for gas-fired cogeneration facilities and recommends that the FERC review the efficiency standards contained in Title 18, Part 292, to promote better thermal matching as a prerequisite to achieving QF status. There must be assurance of meaningful energy conservation. Cogeneration projects whose primary intention is to generate electricity should be discouraged. Alternatively, "PURPA machines" should be subjected to state and federal utility regulation and should be denied preferential price and tax benefits.

While there are benefits for decentralized generation resources, utilities and cogenerators should be on an equal footing with regard to their development. Cogeneration which is unregulated and primarily participating in electrical generation should not have a competitive advantage over comparable utility resources. The current regulations confer such an advantage, and should be changed.

III. The Manner in Which PURPA is Being Implemented is Inconsistent With Present Energy Policy and With the Interest of the Electric Consumer.

A. Current market oriented energy policy should govern PURPA's implementation.

PURPA has been extremely successful in encouraging the development of large amounts of cogeneration and small power production in California. Indeed, post-PURPA cogeneration development is now expected to be three times the amount originally estimated by the FERC when it proposed rules to implement Section 210 of PURPA.

However, as described above, neither FERC nor California regulations implemented PURPA in the manner contemplated by the statute. The electric consumer goals of conservation, efficiency and equitable rates have been ignored in the zealous rush to encourage QF production. The tables and charts described above portray an uneconomic, headlong stampede in California that misallocates resources, ignores electric supply and demand, does not encourage renewable technologies, does not conserve oil and gas, duplicates existing generation, and even fails to "fit" into the operational requirements of the existing electrical system.

It is clearly time to modify PURPA's regulations to assure the electric consumer of the benefits intended by the statute. This conclusion is compelling for another reason. The electric utility industry is subject to a profound and fundamental change in energy policy that is occurring at the federal and state levels. The manner in which PURPA has been implemented to date is utterly inconsistent with the current evolution of electric and natural gas energy policy. Consider the following:

Many utility regulators are examining workable means of introducing "competition" into the bulk power market as a means of improving economic efficiency (e.g., the FERC NOI on coordination and transmission pricing, Docket No. ER85-17). The National Governors Association, National Association of Regulatory Utility Commissioners, and National Association of State Utility Consumer Advocates are also encouraging greater inter-utility coordination transactions (purchase and sale of surplus capacity and energy), and enhanced use of transmission facilities to effect such transactions, for the purpose of i) maintaining the lowest rates, ii) forcing utilities to be more efficient, and iii) encouraging competition among utilities.

Consider also the increasing pressure on utilities by industrial and wholesale customers to go "off-system" and use the transmission system of the utility to purchase and transmit surplus energy from another utility. (See the comments of ELCON and APPA in FERC's NOI, and the comments of various cogenerators at the June 3 hearing before this Committee.) Local regulatory commissions and the FERC are accommodating and in some cases even encouraging such developments (e.g., FERC's Order 436, CPUC gas transportation order, Decision No. 86-03-057).

Consider, finally, the strategy of the Department of Energy, outlined in the National Energy Plan IV, to achieve greater efficiency in energy markets through market-based regulatory policies. These policies encourage greater competition among utilities, market-based pricing of electricity, and loosening of the traditional utility obligation-to-serve tie with the customer's obligation-to-take.

For a utility such as PGandE, the response to these trends is clear: to retain existing customers and attract new customers, PGandE must market its electric service competitively.

To be price and service competitive, PGandE must optimize the use of its electric system, including its transmission system, to i) obtain the lowest-cost supplies, ii) integrate its generating units efficiently, and iii) provide a high level of reliability. PGandE must also be prepared to reduce or expand its "inventory" of electricity capacity and energy quickly to respond to demands of customers who go on and off the system.

As Exhibit 6 shows, over the next four years payments to QFs will become an increasing percentage of PGandE's production expenses. By 1990 QF payments could be 60 percent of PGandE's production expenses. QF overpayment could be 20 percent of PGandE's production expenses. Such operating expenses are passed through to the ratepayers in rates. When payments to QFs exceed the cost the utility would have otherwise incurred and become a significant percentage of the operating expenses, rates increase dramatically and PGandE's competitive position is substantially eroded.

PURPA's demands to pay too much, to buy when power is not needed, and to rely on non-dispatchable facilities is an anomaly in such a competitive energy market. As implemented by the FERC and California, PURPA has erected significant barriers to PGandE's successful participation in today's competitive energy market.

B. Substantive changes in PURPA's implementing regulations are necessary.

Federal and state regulations implementing PURPA must be modified to effect all of the objectives intended by PURPA, instead of the present system where the promotion of alternative energy is pursued at the expense of PURPA's electric consumer objectives. In addition, federal and state regulations, and possibly PURPA itself, must be modified to be consistent with current energy policy favoring competition in the procurement and distribution of bulk power supply.

To assess and implement the recommendations PGandE has advocated above, the FERC should initiate a notice of inquiry (NOI). The NOI would focus on those regulations, both at the federal level and at the state level, that must be modified to correct the problems described above in a manner consistent with current pro-competition energy policy. The final step would be a notice of proposed federal rulemaking and mandatory guidelines to states.

PGandE notes that most of the economic and operating distortions described above have resulted not from inherent flaws in the statute, but from FERC and state regulations that have either misinterpreted PURPA, rigidly pursued certain of its goals at the expense of others, or failed to adjust regulations to changed conditions.

For example, the FERC's regulation mandating payment of the avoided cost price was confirmed in American Paper Institute v. AEP, 461 U.S. 402 (1982), on the grounds of administrative discretion, not because it was the only interpretation possible under Section 210 of PURPA. Indeed, both FERC's reasoning when it promulgated the regulation and the Supreme Court's validation of FERC's regulation were based on conditions then existing, which justified maximum incentives for QF development. Based on today's economic conditions, FERC's avoided cost regulations should be changed to specifically allow and encourage states to pay less than avoided costs, to the extent it would both encourage sufficient QF production (not exceeding need) and provide electric consumers with rate benefits.

V. Conclusion.

The FERC and the states, including California, have an obligation to undertake an assessment and modification of their PURPA regulations in light of today's supply and demand conditions and changing energy policy.

> This Commission has an ongoing responsibility to reassess the consistency of its rules in the light of the realities of electric power markets; rules that were proper to overcome inertia and initial resistance to the development of cogeneration may need change as the industry matures. (Commissioner Stalon's statement in Applied Energy Services, Inc. vs. Oklahoma Corporation Commission, Docket No. EL85-25-000, 31 FERC Par. 61,313 at 61,711.)

If the FERC fails to complete its investigation and propose new PURPA rules within six months of this Committee's request for an NOI, legislative amendments to PURPA should be enacted to direct FERC and the states to implement the statute consistent with the following recommendations.

- QF pricing should both stimulate QF development and achieve maximum rate benefits for electric consumers, not to exceed true avoided cost.

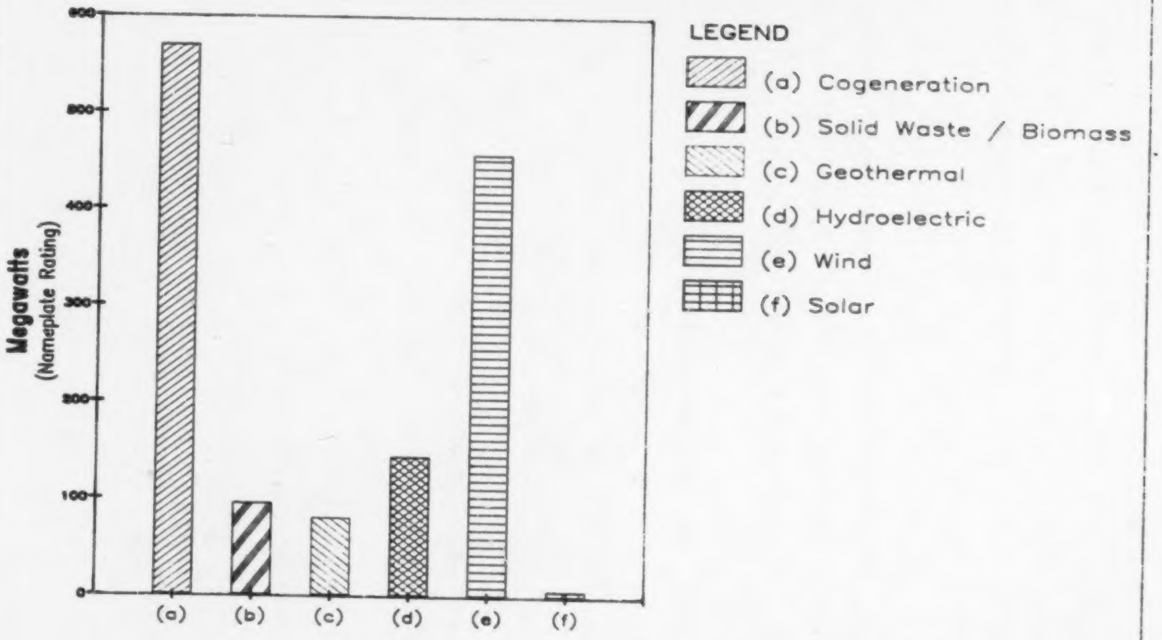
- Capacity payments and purchases should be made only for those years in which a deferrable or avoidable utility resource is specifically identified in the near-term resource plan.

- Contracts between a utility and a QF must be individually negotiated to provide needed performance characteristics to achieve system efficiency and reliability.

- QF status should be withheld from token cogenerators that are designed as electric power plants and which do not achieve efficiency improvements.

Exhibit 1

QUALIFYING FACILITY CAPACITY
Operational as of December 31, 1985

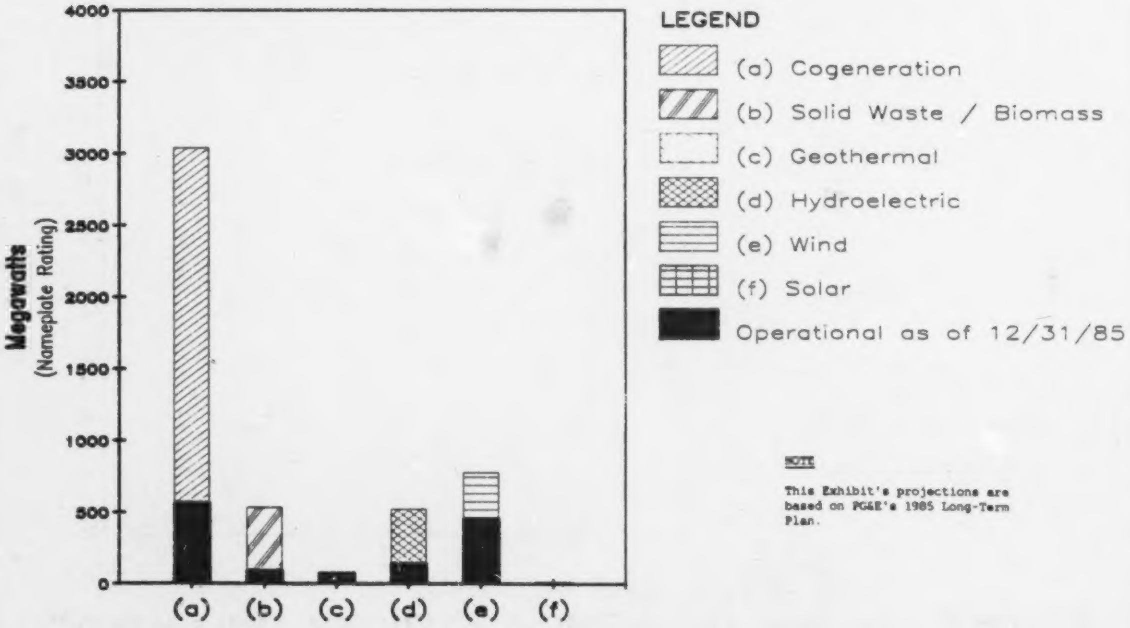


Pacific Gas and Electric Company – June 1986

Exhibit 2

QUALIFYING FACILITIES CAPACITY

Projected to be Operational by December 31, 1990



NOTE

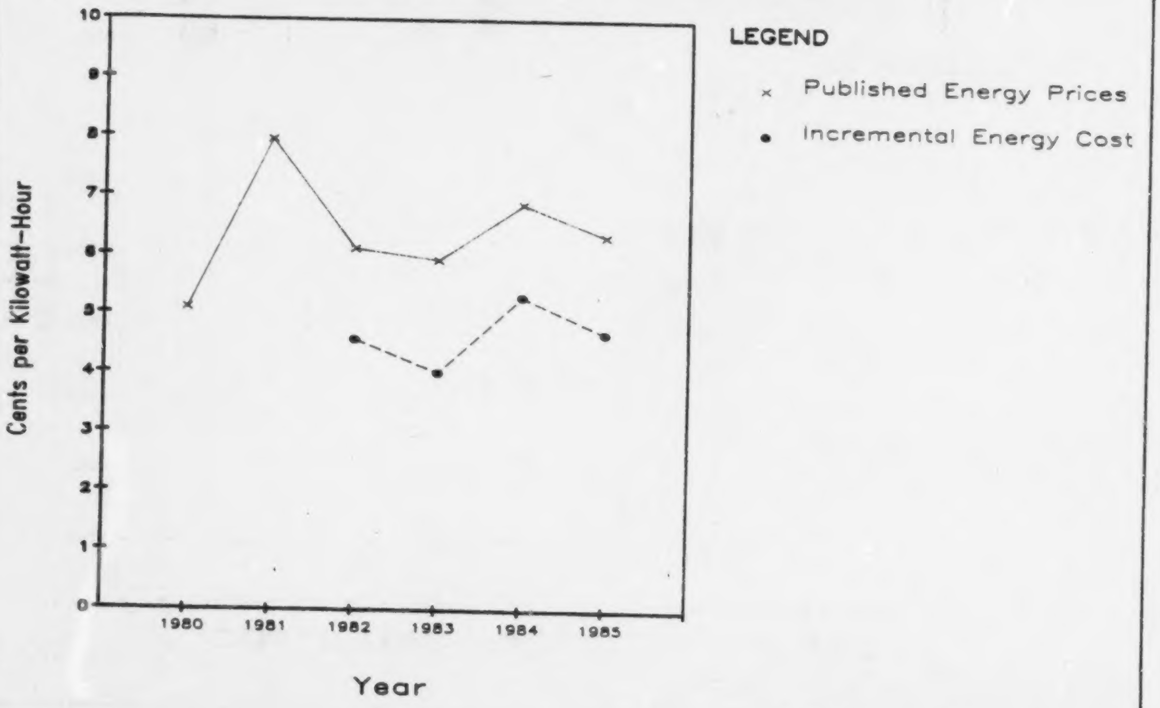
This Exhibit's projections are based on PG&E's 1985 Long-Term Plan.

Pacific Gas and Electric Company – June 1986

Exhibit 3

QUALIFYING FACILITY PUBLISHED ENERGY PRICES

vs. PGandE System Incremental Energy Costs



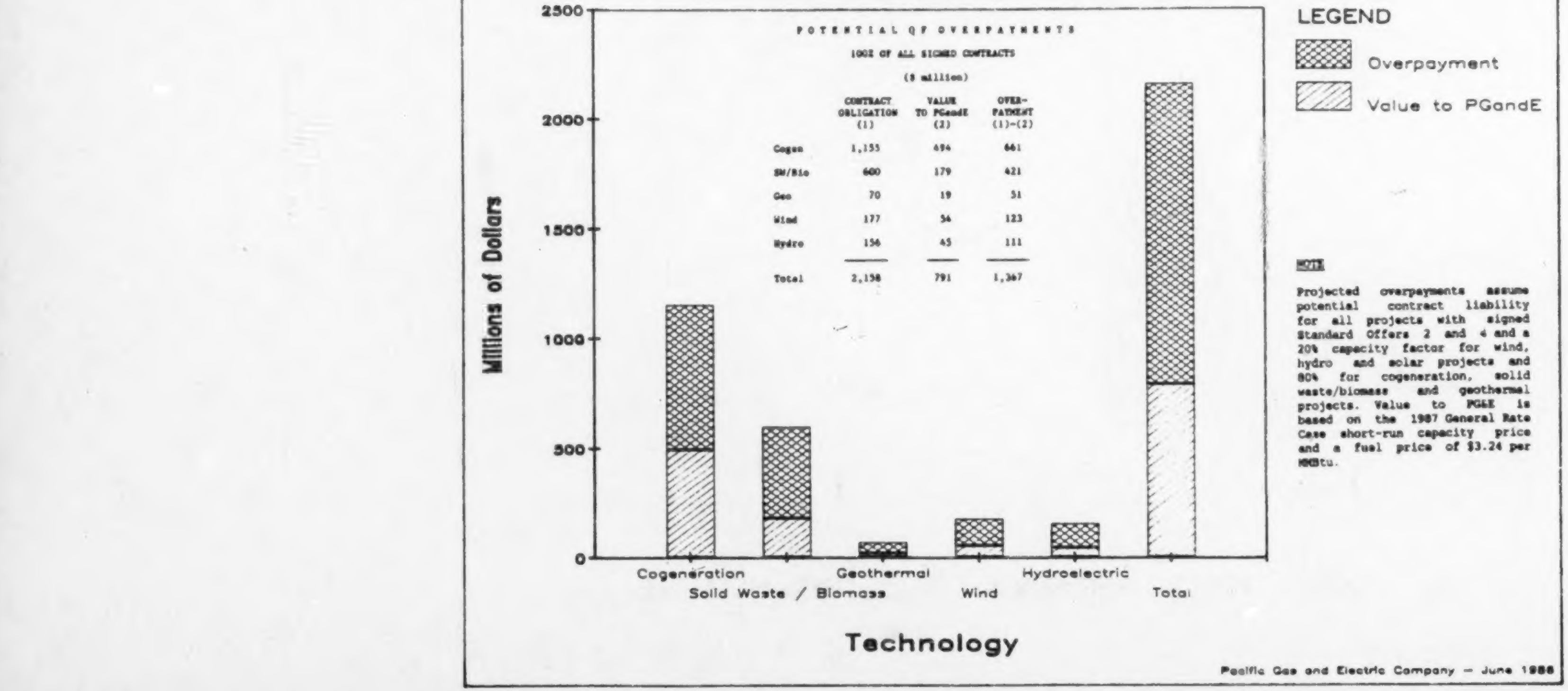
Pacific Gas and Electric Company – June 1986

Exhibit 4

POTENTIAL OVERPAYMENTS IN 1990

To QFs with Fixed Price Contracts (SO2 and SO4)

(Based on 100% Project Success Rate)



POTENTIAL QF OVERPAYMENTS

100% OF ALL SIGNED CONTRACTS

($ million)

	CONTRACT OBLIGATION (1)	VALUE TO PGandE (2)	OVER-PAYMENT (1)-(2)
Cogen	1,155	494	661
SW/Bio	600	179	421
Geo	70	19	51
Wind	177	54	123
Hydro	156	45	111
Total	2,158	791	1,367

NOTE

Projected overpayments assume potential contract liability for all projects with signed Standard Offers 2 and 4 and a 20% capacity factor for wind, hydro and solar projects and 80% for cogeneration, solid waste/biomass and geothermal projects. Value to PG&E is based on the 1987 General Rate Case short-run capacity price and a fuel price of $3.24 per MMBtu.

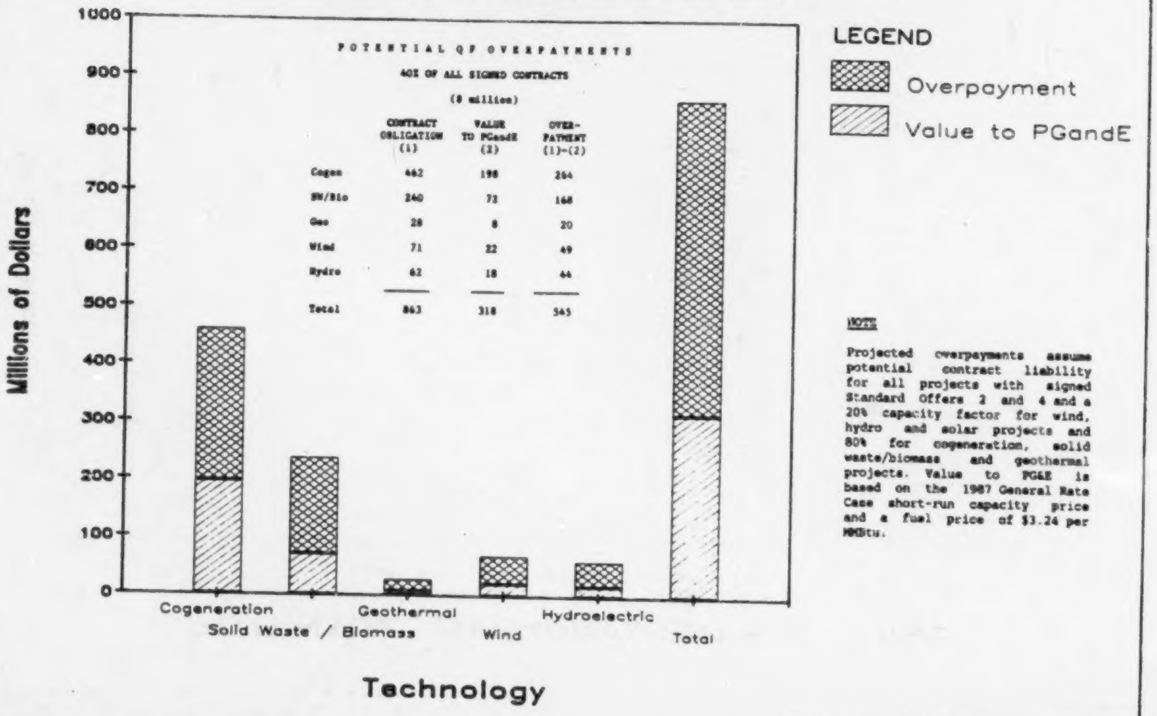
Pacific Gas and Electric Company – June 1988

Exhibit 5

POTENTIAL OVERPAYMENTS IN 1990

To QFs with Fixed Price Contracts (SO2 and SO4)

(Based on 40% Project Success Rate)



POTENTIAL QF OVERPAYMENTS

40% OF ALL SIGNED CONTRACTS

($ million)

	CONTRACT OBLIGATION (1)	VALUE TO PGandE (2)	OVER-PAYMENT (1)-(2)
Cogen	462	198	264
SW/Bio	240	72	168
Geo	28	8	20
Wind	71	22	49
Hydro	62	18	44
Total	863	318	545

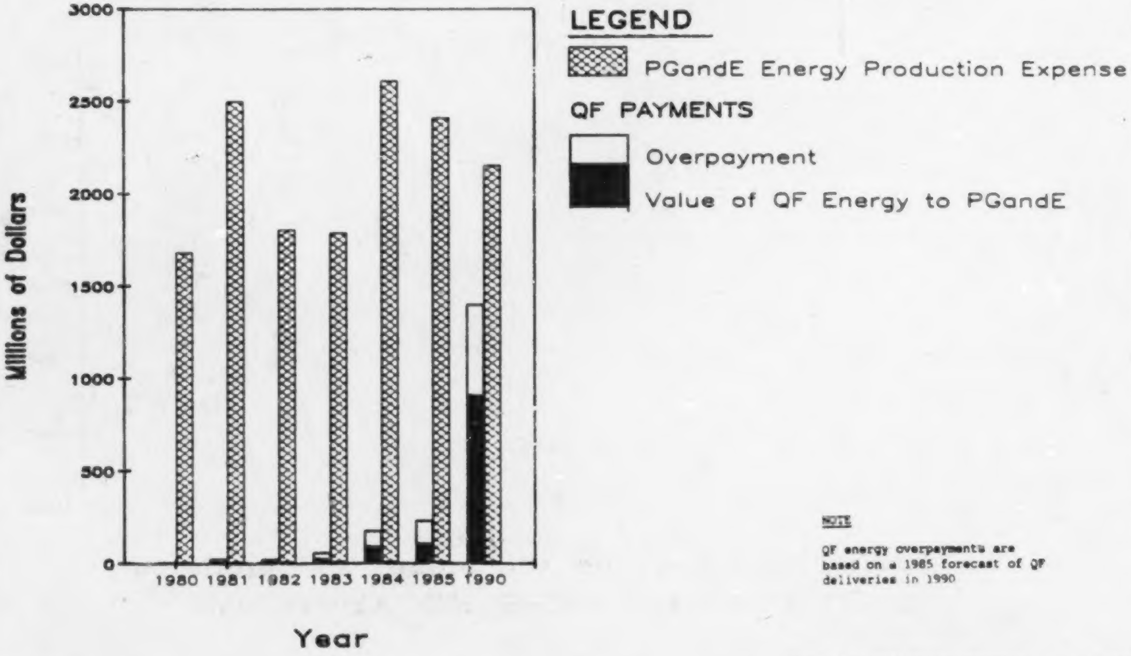
NOTE

Projected overpayments assume potential contract liability for all projects with signed Standard Offers 2 and 4 and a 20% capacity factor for wind, hydro and solar projects and 80% for cogeneration, solid waste/biomass and geothermal projects. Value to PG&E is based on the 1987 General Rate Case short-run capacity price and a fuel price of $3.24 per MMBtu.

Pacific Gas and Electric Company – June 1988

Exhibit 6

QUALIFYING FACILITIES ENERGY PAYMENTS
COMPARED TO PGandE PRODUCTION EXPENSE



NOTE

QF energy overpayments are based on a 1985 forecast of QF deliveries in 1990

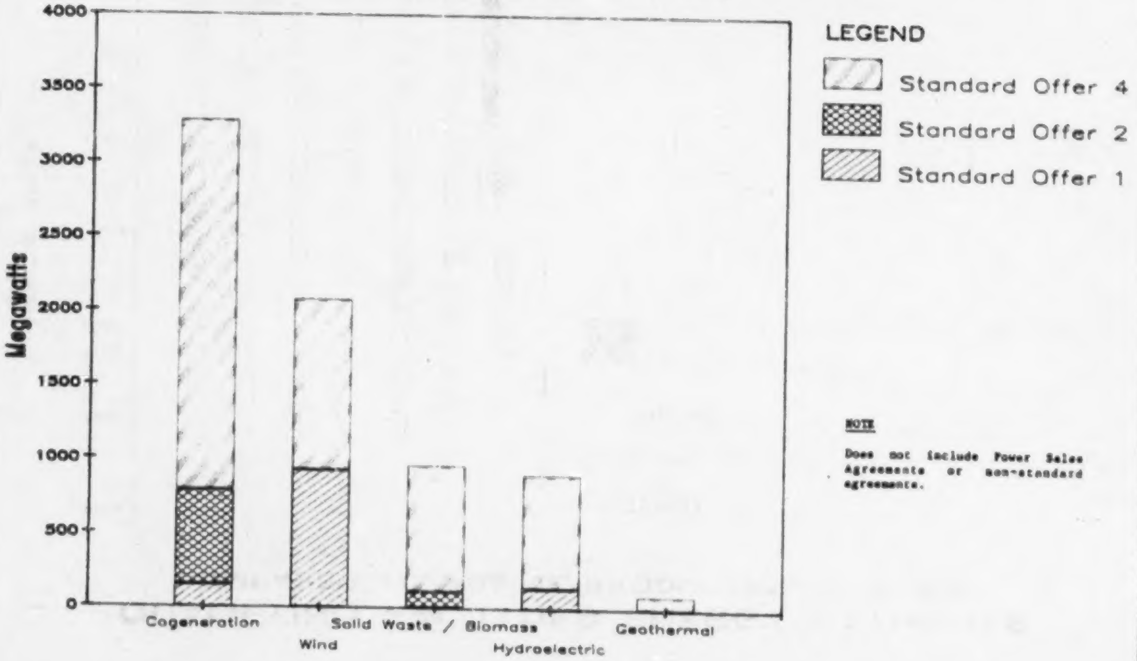
Pacific Gas and Electric Company – June 1985

Exhibit 7

SUMMARY OF SIGNED CONTRACTS

Segregated by Technology and Standard Offer Type

(as of March 31, 1986)



NOTE

Does not include Power Sales Agreements or non-standard agreements.

Pacific Gas and Electric Company — June 1986

Exhibit 8

SUMMARY OF SIGNED CONTRACTS

Cumulative Megawatt[1] Totals of Qualifying Facilities
Segregated by Technology

As of March 31, 1986

Technology	Standard Offer 1	Standard Offer 2	Standard Offer 4	Other[2] (MW)	Total (MW)
Cogeneration	150.5	640.7	2497.4	535.6	2814.2
Solid Waste	4.2	108.5	852.7	199.5	1164.9
Geothermal	0.0	0.0	94.9	80.0	174.9
Hydroelectric	138.1	1.2	767.5	39.5	946.3
Wind	929.3	0.0	1154.5	117.0	2200.8
Solar	0.0	0.0	0.0	16.5	16.5
Total MW	1222.1	750.4	5367.0	988.1	8327.6
(% of Total)	(14.7)	(9.0)	(64.4)	(11.9)	

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[1] Megawatts are full nameplate rating of facility as defined in each PPA.

[2] This category includes "Power Sales Agreements" which were the predecessors of the standard offers.

Exhibit 9
Page 1 of 2

TYPE	STATUS	ENERGY PAYMENTS	CAPACITY PAYMENTS	POSITIVE/NEGATIVE FEATURES
Interim S.O. #4 Long-Term Energy and Capacity	Suspended 4/17/85 5367 MW 64.4% of QF contracts	3 energy payment options: Opt 1 - Forecasted prices* Opt 2 - Levelized forecasted prices* Opt 3 - Incremental energy rates set for years up through 1990, actual fuel price *QF gets prices for up to 10 years depending on contract length	3 capacity payment options: Opt 1 - Same as S.O. #1 Opt 2 - forecasted as-delivered capacity payments for up to 10 years, thereafter no lower than 10th year price. Opt 3 - Same as S.O. #2 for firm deliveries but also as-delivered payments for deliveries above firm.	POS. - contains an optional curtailment - alternate price provision for 1000 off-peak hours annually. NEG. - Both energy and capacity prices fixed for long periods - no adjustment if actual avoided costs are different.
S.O. #3 As-delivered Capacity and Energy for QFs 100 KW or less	Available	Same as S.O. #1 except QFs without time of delivery metering receive weighted average energy prices	Same as S.O. #1 except QFs without time of delivery metering receive 50% of the price.	POS. - Small projects only - some "discount" from avoided cost. NEG. - none

PGandE's problems with the implementation of the QF program have stemed primarily from standard offers 1, 2 and 4. However, for informational purposes, Standard Offer No. 3 has been included in this chart.

Exhibit 9
Page 2 of 2

SUMMARY OF PGANDE STANDARD OFFERS FOR QF POWER PURCHASES

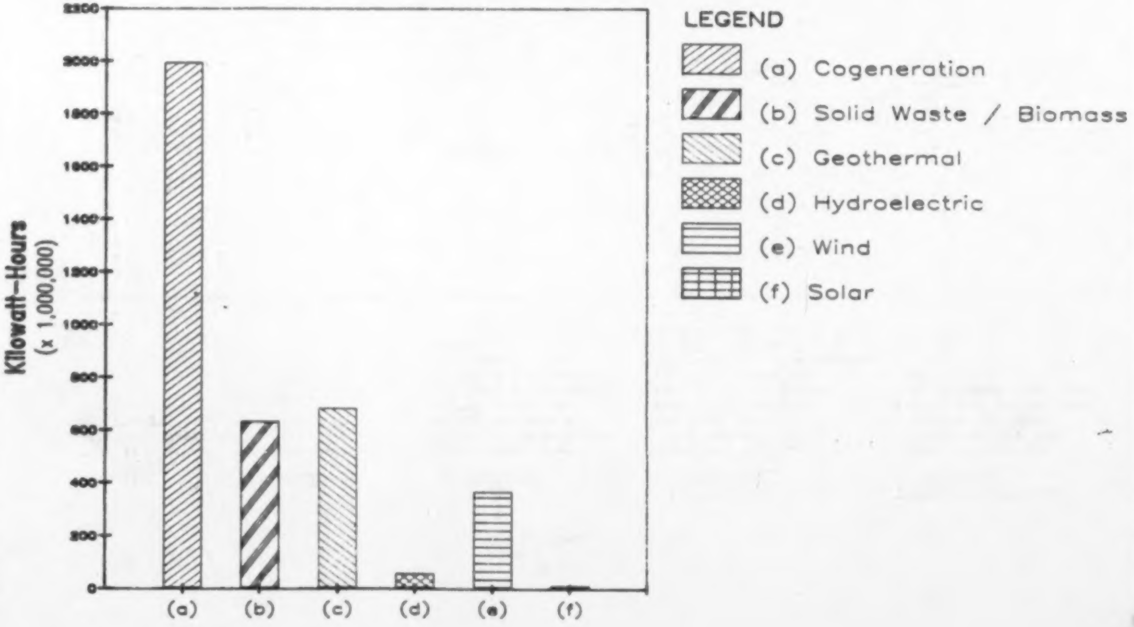
TYPE	STATUS	ENERGY PAYMENTS	CAPACITY PAYMENTS	POSITIVE/NEGATIVE FEATURES
S.O. #1 - As-delivered capacity and energy	Available 1222.1 MW 14.7% of QF contracts	Prices published quarterly calculated using incremental energy rates (in BTU/KWH) established in GRC's and current incremental fuel costs.	Based on "shortage" value concept using the cost of a combustion turbine as a proxy, adjusted to reflect system reliability. Established in GRC's and paid in cents per KWH.	POS. - Prices are not locked in for long periods of time. NEG. - No performance requirements for the QF.
S.O. #2 Firm Capacity and Energy	Suspended 3/19/86 750.4 MW 9% of QF contracts	Same as S.O. #1	Calculated the same as S.O. #1 but forecast for up to 30 years and levelized. QF's price depends on length of contract term.	POS. - On-peak, summer performance requirements. NEG. - Forecast errors can result in overpayments; no opportnity to adjust prices to actual avoided cost.

Exhibit 10

QUALIFYING FACILITIES ENERGY DELIVERIES

For the Year Ending December 31, 1985

(Projects Greater Than 1 Megawatt)



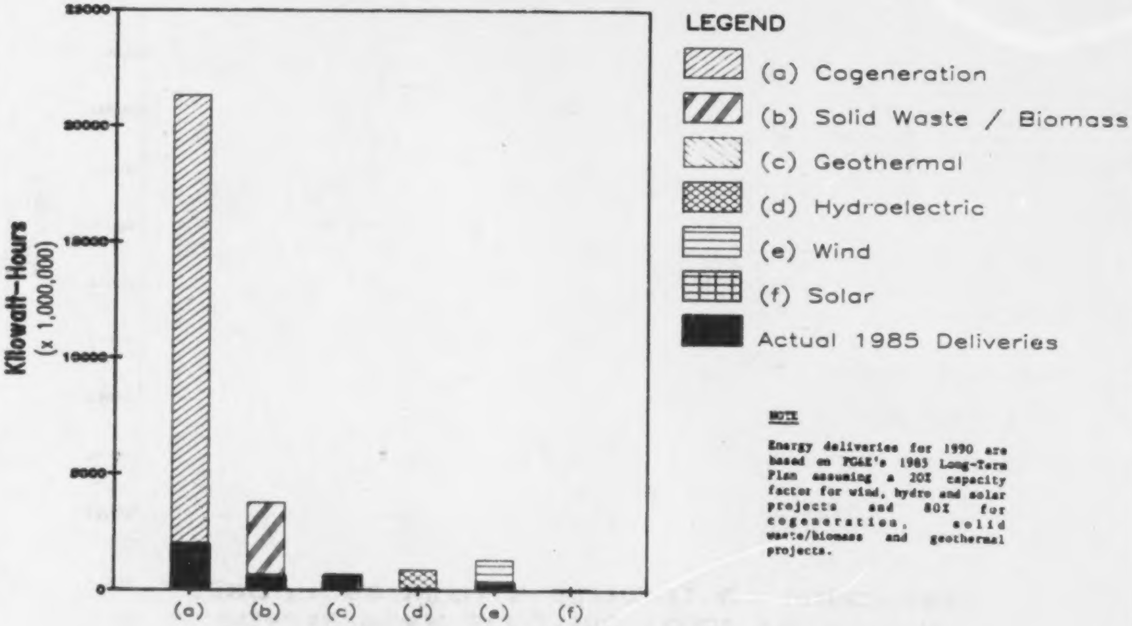
Pacific Gas and Electric Company – June 1986

Exhibit 11

QUALIFYING FACILITIES ENERGY DELIVERIES

Projected for the Year 1990

(Projects Greater Than 1 Megawatt)



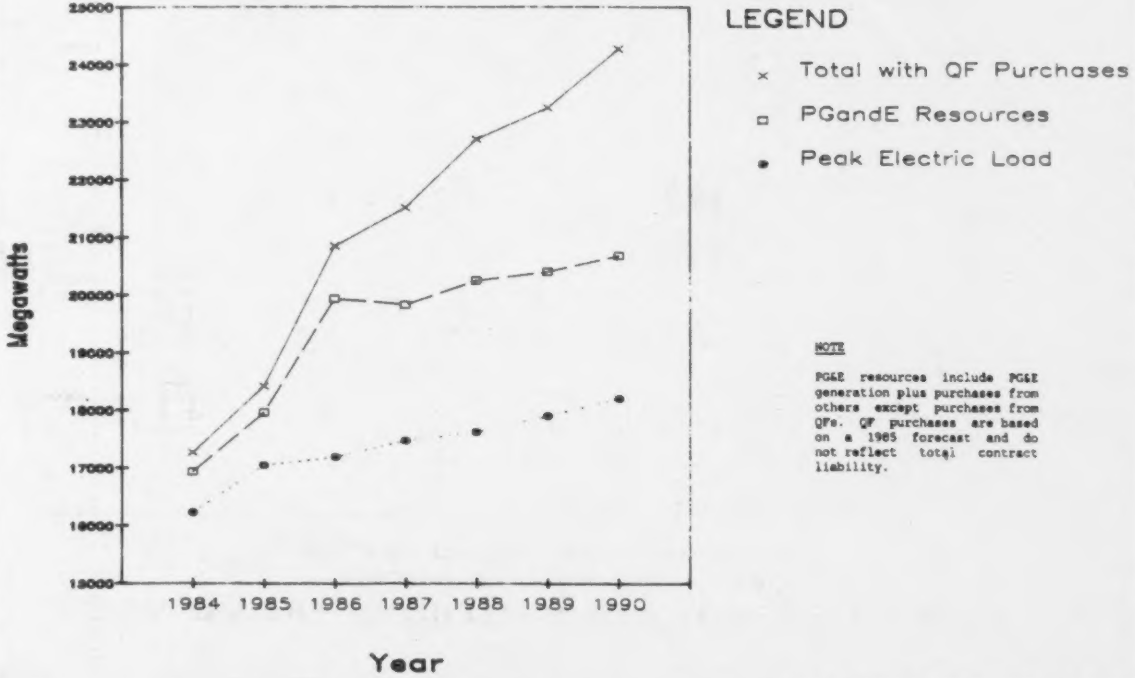
NOTE

Energy deliveries for 1990 are based on PG&E's 1985 Long-Term Plan assuming a 20% capacity factor for wind, hydro and solar projects and 80% for cogeneration, solid waste/biomass and geothermal projects.

Pacific Gas and Electric Company – June 1986

Exhibit 12

PGandE PEAK ELECTRIC LOAD VS. PGandE RESOURCES WITH & WITHOUT QF PURCHASES



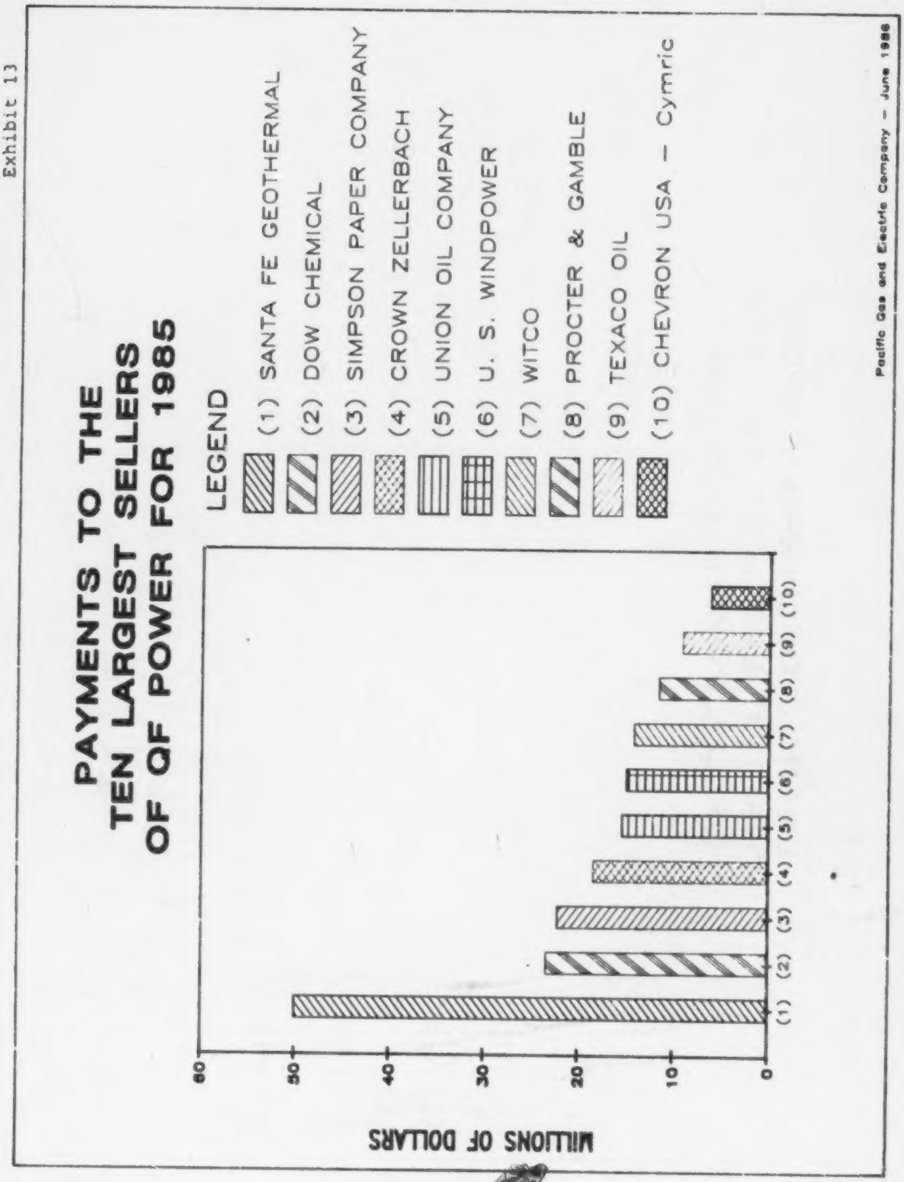
NOTE

PG&E resources include PG&E generation plus purchases from others except purchases from QFs. QF purchases are based on a 1985 forecast and do not reflect total contract liability.

Pacific Gas and Electric Company – June 1986

Exhibit 13

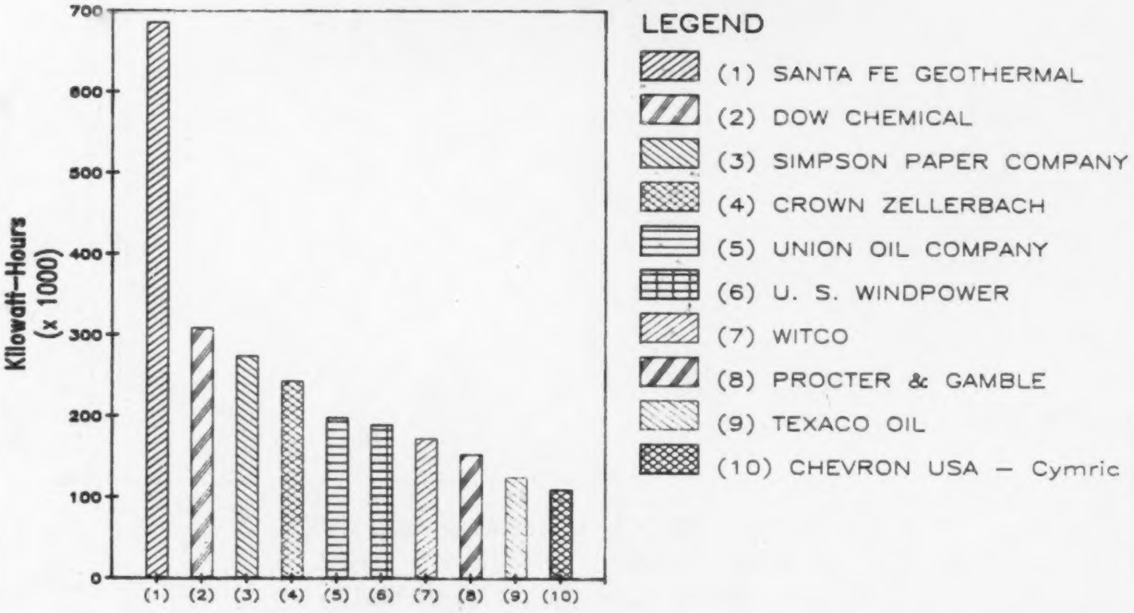
PAYMENTS TO THE TEN LARGEST SELLERS OF QF POWER FOR 1985



Pacific Gas and Electric Company - June 1986

Exhibit 14

ENERGY DELIVERIES FROM THE TEN LARGEST SELLERS OF QF POWER FOR 1985



Pacific Gas and Electric Company – June 1986

PREPARED COMMENTS BY SOLAR TURBINES INCORPORATED

for the

U.S. Senate Committee on Energy and Natural Resources
Oversight Hearing on Implementation of the
Public Utility Regulatory Policies Act of 1978

June 3 & 5, 1986

J.C. Solt
Manager, Cogeneration

Solar Turbines Incorporated
9250 A Skypark Court
San Diego, CA 92123
(619) 694-6153

INTRODUCTION

Solar Turbines Incorporated is a wholly owned subsidiary of Caterpillar Inc. Solar has been providing equipment in cogeneration systems since 1960 and currently has over 500 gas turbine engines in cogeneration.

Through our involvement in this market in the last few years, we have developed several concerns about the PURPA regulations as they presently exist and some of the proposed revisions to these regulations.

Many publications and reports have referred to the "incentives" provided to cogenerators by PURPA. In fact, PURPA provided no incentives to fossil-fueled cogeneration systems. It did remove some regulatory and utility obstacles that had limited the growth of cogeneration. The primary value of PURPA to a cogenerator is that it made him free to do business without being discriminated against by the monopolistic utility or drawn into regulation by utility commissions that were created to regulate the activities of the monopolistic utilities, not the independent cogeneration facilities.

Some cogeneration opponents have argued against the requirement for electric utilities to pay "net avoided cost" for power sold by qualifying cogeneration facilities. Although it may be difficult to determine precisely what net avoided cost is, the basic concept appears to be the correct one.

Unless the electric utility or the rate payers are involved in the cost and/or risk of the cogeneration system, it would be inappropriate for them to subsidize or profit from that system. The concept of using net avoided cost should accomplish that balance. If, in fact, the price being paid by the utility results in the rate payer subsidizing the cogenerator, it would suggest that the computation for net avoided cost is incorrect. Net avoided cost should leave the utility and rate payer ambivalent.

SOLAR'S CONCERNS

Solar's primary concern with PURPA regulations as they presently exist has to do with the proliferation of very large systems using "PURPA machines" that consume capacity credits and do not optimize energy conservation. To clarify our concerns we will:

- Discuss precisely what Solar means by "PURPA machine."
- Discuss how PURPA regulations have encouraged the development of these systems in certain sections of the market.
- Explain the impact they have on energy conservation.
- Suggest PURPA revisions which would eliminate the abuses.

PURPA MACHINE

Although it is true that the thermal load establishes the basis for the size of the cogeneration system, there are some flexibilities that exist in the amount of power produced. If the owner wants to minimize power production (and capital cost) to satisfy a given thermal requirement, he can install a gas turbine and supplementally fire additional fuel in the turbine exhaust so that the entire thermal requirements can be met with relatively little power production. By installing more gas turbine capacity and eliminating the supplemental firing, the same thermal load can be met with two to three times as much power. If the turbine exhaust is used to produce high pressure steam, this high pressure steam can be passed first through a backpressure steam turbine and then to the thermal load. More power can be produced with the same process heat load.

Carrying this further, the turbine exhaust can be used to produce high pressure steam which can then go into an extraction steam turbine. The steam required for the process can be extracted from the steam turbine and the remainder of the steam can go through the low pressure section of the steam turbine to a surface condenser. A system requiring 50,000 pounds per hour of steam can be satisfied with a system producing as little as 3.6 MW and typically as much as 83 MW. In fact, it is possible to go as high as 278 MW while still qualifying for PURPA benefits. (See Figure 1 and Table 1.)

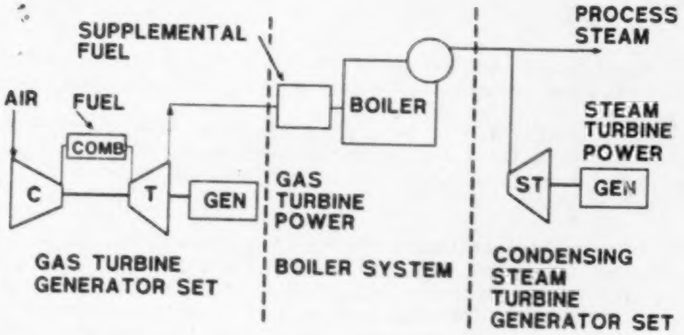

SUPPLEMENTAL
FUEL
PROCESS
STEAM
AIR
FUEL
COMB
BOILER
STEAM
TURBINE
POWER
C
T
GEN
GAS
TURBINE
POWER
ST
GEN
GAS TURBINE
GENERATOR SET
BOILER SYSTEM
CONDENSING
STEAM
TURBINE
GENERATOR SET

Figure 1. Alternative Cogeneration Systems

Cogeneration systems which produce very large amounts of electricity to satisfy relatively small thermal requirements are frequently referred to as "PURPA machines".

Table 1. Comparison of Alternative Cogeneration Systems

Parameter	With Supplemental Firing (to 1720°F)	Supplement Firing	Output Energy in Heat	
			15%	5%
Electrical Output, MW	3.6	8.7	83	278
Supplemental Fuel, MMBtu/hr	30.8	0	—	—
Total Fuel Input, MMBtu/hr	78.3	115	725	2164
Steam Output, lb/hr	50,000	50,000	50,000	50,000
PURPA Compliance, %	47.6	47.5	42.5	45
Power to Heat Ratio, kW/10,000 lb of steam	720	1740	16,600	55,600
Fuel Saved Using 300 MW of Capacity Credit*				
10^6 Btu/MW-hr	4.5	2.9	.994	1.41
10^{12} Btu/yr	11.83	7.62	2.61	3.71

* Based on a marginal heat rate of 8970 Btu/kW-hr per PG & E Std. offer #4 May 1984.

SYSTEM SELECTION

The type of system selected depends on the financial objectives of the owner. For purposes of these comments, we are considering two types of owners:

- **User-Owned System** - In this type, the owner purchases or leases a system for a facility requiring thermal energy. The owner provides the fuel and, if excess electrical power is generated, he sells it to the electric utility.

- **Third-Party Cogeneration System** - In a third-party venture, a company is formed to finance, own, and operate the cogeneration system. The heat user signs a long-term contract which obligates him to buy heat and possibly power from the venture. This venture produces heat for sale to the heat user and power for sale to the heat user, the electric utility or both.

Since the financial objectives of the user-owned and third-party venture systems are different, we see sharp differences in the type of systems selected by each.

Most user-owned systems are designed to satisfy the base electrical and thermal loads. Accordingly, there is little or no export of power, and it is common to find supplemental firing used to accomplish this balance. This type of system maximizes the Internal Rate of Return (profitability), which is usually the primary objective of the user-owned system.

A system owned by a third-party venture usually tries to maximize power production, building the largest system possible which satisfies the thermal requirements. Frequently employing a condensing steam turbine system behind a gas turbine, this system results in the export of very large quantities of power into the utility grid. This becomes desirable because of the economic objectives of the third-party venture. If the general partner is putting in little or none of his own capital, the Internal Rate of Return does not need to be maximized; it only needs to exceed the level required to attract investors (for example, 15-20% after taxes). The general partner then benefits from having a large system. If a project is being competitively bid by several third-party developers, installing the less efficient larger system allows a third-party developer to offer a more attractive rate to the thermal energy purchaser.

IMPACT ON ENERGY CONSERVATION

As cogeneration development has demonstrated, the economics of a specific project depend on the costs and capacity requirements of the local utility. Many projects require a significant capacity credit in order to be economically viable. Since the capacity requirements for any utility are limited (if, in fact, there is any requirement), installation of "PURPA machines" within a utility service territory will dramatically reduce the amount of energy which could be conserved by cogeneration within that utility service territory. The bottom row of Table 1 indicates what this fuel savings could be in a utility service territory with a capacity requirement of 300 megawatts.

SUGGESTED CHANGES

Qualification by Thermal Load

An earlier FERC interpretation indicated that, if the thermal load would not have existed without the cogeneration system, the system would not qualify for PURPA benefits. Under this interpretation, a combined-cycle system would not qualify since the Rankine cycle thermal load would not exist were it not for the cogeneration topping cycle.

The problem described above seems to relate only to extraction steam turbine systems. It appears that the problem would be resolved if FERC granted qualification status only to the percentage of the cogeneration system for which the steam is being condensed in a heat load. If the steam is being condensed in a surface condenser or being rejected to the atmosphere, that percentage of the system would not qualify.

Qualification of any portion of the system would entitle the system to utility interconnection. However, it would not obligate electric utilities to pay net avoided cost for the unqualified percentage of the system. It also would not exempt that portion of the system from regulation as a utility.

Cogeneration is still the best energy conserving technology available to the United States today. Solar strongly urges the committee to seek a solution to this problem which will allow the continued development of legitimate energy conserving cogeneration. The solution should require compliance with energy conservation criteria, not limit ownership alternatives.

Power Wheeling

Solar's second major concern is with regard to the ability of a cogenerator to wheel excess power to other facilities within the same utility service territory or to other electric utilities that may require additional capacity.

Power wheeling is a term used to describe the process when the electric utility grid is used by another company, such as a cogenerator, to transport power from one place to another (Figure 2). If the electric utility agrees to transport the power in this fashion, there is usually a fee charged for the service.

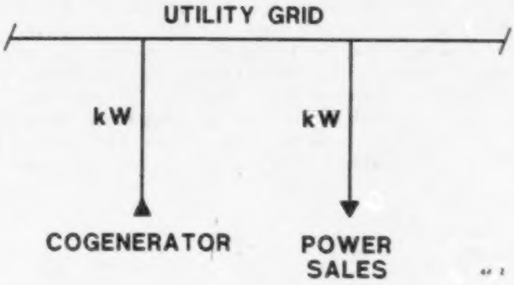


Figure 10. Power Wheeling

PURPA provides cogenerators with the assurance that any electric utility which is offered cogenerated power must purchase it at the "net avoided cost". This is **not limited** simply to the electric utility in whose service territory the cogeneration system resides.

PURPA does not require any utility to wheel power. Accordingly, a large number of cogeneration opportunities are going unrealized because the local utility refuses to wheel the power at a reasonable cost to another facility or a neighboring utility which can use the capacity.